COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
Preparation of the 2007	)	Docket No.
Integrated Energy Policy	)	06-IEP-1A
Report (2007 IEPR)	)	
	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, OCTOBER 16, 2007

9:00 A.M.

Reported by:
John Cota
Contract No. 150-07-001

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

Jeffrey Byron

John Geesman, Associate Member

Arthur Rosenfeld

CPUC COMMISSIONERS PRESENT

John Bohn

ADVISORS PRESENT

Steve St. Marie, CPUC

STAFF and CONTRACTORS PRESENT

Pam Doughman (via telephone)

Matt Dowell

Michael Jaske, PhD

Linda Kelly

Bill Knox

Michael Messenger

John Sugar

Lorraine White

ALSO PRESENT

Robert Anderson, San Diego Gas & Electric

Les Guliasi, Pacific Gas and Electric Company

Cliff Chen, Union of Concerned Scientists

Tim Vonder, San Diego Gas and Electric

Robert E. Burt, Insulation Construction Association

Richard Aslin, Pacific Gas and Electric Company

H. I. Bud Beebe, Sacramento Municipal Utility District

Phillip J. Muller, Mirant

Audrey Chang, Natural Resources Defense Council

Paul Vercruyssen, Center for Energy Efficiency and Renewable Technologies

Cynthia Mitchell, Energy Economics, Inc.

Jacqueline G. Gones, Southern California Edison

Angela Haren, California Coastkeeper Alliance (via telephone)

Livia Borak, San Diego Coastkeeper (via telephone)

Joseph Langenberger, Central California Power (via telephone)

Eric Wong, Cummins Power Generation (via telephone)

Rosemary McMichael, Current Group, LLC (via telephone)

Nora Sheriff, Association of Energy Producers and Users (via telephone)

I N D E X

P R O C E E D I N G S

9:00 a.m.

PRESIDING MEMBER PFANNENSTIEL: Good morning. I think we're ready to begin. This is the Energy Commission hearing on the Integrated Energy Policy Report. The second full hearing on the entire report that was published in draft, the Committee Draft, on October 2. And we are here to cover certain full sections of the report. There were some that were done yesterday and we'll go through the remainder of the report today.

I am Commissioner Jackie Pfannenstiel. I am the Presiding Commissioner on the IEPR Committee. Joining me on the dais to my right is Commissioner Geesman, who is the Associate Member on the IEPR Committee.

To his right is Commissioner John Bohn from the PUC who has worked with us throughout the IEPR process and we are delighted to have Commissioner Bohn with us today.

To my left is Commissioner Jeff Byron who is the presiding member of the Commission's Electricity Committee.

To his left is Commissioner Art Rosenfeld, who is the Presiding Member of the R&D

Committee and a member of the Efficiency Committee.

And I think that we are all ready to get going so Lorraine we return to you.

MS. WHITE: Thank you, Commissioner.

Good morning everyone and welcome. We are delighted that you could join us today and participate in the second of two days worth of hearings, as the Chairman has mentioned, on the Committee's Draft 2007 Integrated Energy Policy Report.

I am Lorraine White, I am the program manager for the Commission's proceeding and will be providing some introductory comments this morning and also a brief summary of the initial chapter of the Committee's report, which provides the context in which we have developed the policy recommendations for the 2007 Integrated Energy Policy Report.

Of course we always have the logistics to go over first. The facilities here essentially have a snack bar on the second floor under the awning. There's restrooms to the left and also restrooms behind the elevators.

We also have provided for Web-Ex

services to facilitate remote participation in the proceedings. To facilitate actual comments and questions that those remote participants may have we have provided a call-in number. The number is 1-800-857-6618. When you join in the call you will be asked for a passcode. That is IEPR. I am the call leader.

For those who are participating here in person: We will be essentially asking throughout the course of the discussions for people to make comments and ask any questions that they may have. To help facilitate that process we ask that you use our blue cards so that we can indicate to the Chairman and other Commissioners who might be having questions. Those blue cards can be found in the foyer.

All of the materials for today's discussions as well as materials related to yesterday's presentations are also out in the foyer.

The first day's discussions were predominately focused on the transportation and land use side. We also had discussions on natural gas and the analyses and forecasts that are involved in those particular assessments.

Today we are going to be looking at the results of the electricity-related assessments. We will also be discussing the chapter on energy efficiency, which highlights AB 2021 work setting statewide goals for energy efficiency. We are going to be looking at the renewables resource and staff's analysis of that particular sector. And then finally we'll conclude with a discussion on the electricity distribution system chapter and the analysis there.

The staff that will be providing these discussions are listed in the agenda also out in the foyer.

Just a quick summary regarding the specific requirements that we are satisfying as a part of this proceeding. About 18 months ago we began the process of assessments and analyses to develop forecasts on energy resource supply, demand and price.

On the first of May the Committee had issued their request for a scoping order, we had a hearing. The scoping order was finalized in August of '06. That formally started our process.

We have been engaging various market participants throughout this entire process to

gather information, to engage them in discussions about that information and refine any details as necessary.

An important part of our proceeding is also the consultations that we have with other agencies, and in particular we have been really pleased with the cooperation and participation that we have had with particularly the PUC but also other state agencies and the ISO.

Throughout this proceeding we have benefitted a great deal from the public participation that we have received. We have held more than 45 public meetings to date throughout this entire proceeding, both for the 2006 update and the 2007 IEPR. It is from all of this analyses, information gathering, discussion and public participation that the Committee has developed and is now recommending various policies to address the issues identified.

OF course this is a process we repeat every two years since the legislation was passed in 2001 requesting us to do this work. We expect actually complete this work and transmit the final report adopted by the Commission by the end of November.

I mentioned the 2006 Integrated Energy Policy Report Update. This was an important document that provided a mid-course review of the renewable portfolio standard work underway with the state. It also provided an initial discussion of the relationship between land use and energy.

Yesterday we completed that discussion regarding land use as part of the chapter overview that we provided. Today we will continue the discussion on the renewable-related resource analysis. The update was adopted on January 3 of 2003 -- pardon me, 2007.

For those of you that would like to provide written comments we ask that those comments be provided by October 19 so that the Committee can publish their document by November 7 in order to be adopted at the November 21 Business Meeting.

And last but not least of course, information can be obtained about this entire proceeding on the Energy Commission's website. If there's no questions about the overview of the proceeding and the logistics, Chairman, we will go right into the chapter overview. Okay.

The initial chapter provides the context

in which the analyses and policy recommendations have been couched. The title of the chapter is Meeting California's Energy Needs in a Carbon Constrained World.

Although that sounds obvious I want to make sure everybody is clear it's in the context of AB 32, the California Global Warming Solutions Act. And in that we highlight a quote from Governor Schwarzenegger:

> "The debate is over. We know the science. We see the threat. And we know that the time for action is now."

This IEPR is not about rehashing the issue of global climate change but is done in the recognition that that is the new paradigm. So to set the stage for the work that we have done we provided some information and context.

California is a very large state with a very large population. To date current population estimates are that there are 37 million California residents. The Department of Finance predicts that there will be more than 40 million by 2020, specifically 44.1 million. That was from their July forecast.

Current estimates are that California is the eighth largest economy in the world. We are the second largest consumer of gasoline and we are also the twelfth largest emitter of greenhouse gas emissions.

So when looking at AB 32 in the context of information, and the diverse resources both instate and imported that we use to fuel our economy and meet the needs of Californians, AB 32 is a formidable task.

So we wanted to provide an energy profile. And this is a correction I would like to make in the handout. I had the labels for these pie charts switched. So the bottom left is actually the source and the upper right is consumption.

When you look at the resources that California depends upon to meet its needs a significant number of those resources and a significant amount come from carbon-based resources and provide a significant contribution to the GHG emissions that are part of our footprint.

In terms of the resources that we consume, about half of it is for transportation.

So that information provides the starting point from which we are actually going to begin our work to address GHGs.

This particular graph provides information on the energy resources and their contribution. Seventy-five percent of California's gross GHG emissions as of 2004 are attributable to refining electricity generation, both instate and imported, as well as transportation. When looking at the sectors that could be used to help us reduce those emissions they jump out at you.

But we also have to address the existing energy concerns that meet the needs of the state of California and its residents in the future. We have growing demand. With growing demand you have growing issues related to infrastructure, resource adequacy, fuel diversity, environmental quality and the long-term uncertainty associated with bringing those resources within the economy and to consumers.

But things are changing. California's distribution of population in the state, which in the '50s was predominately along the coast, as we look to the future will be more and more inland.

That has an effect on the types and nature of the energy demands that we will be having to address.

So to address the needs for powering the state in the future we know that the best option in an AB 32 world is efficiency and conservation of resources.

We realize that to provide for the economy and consumers the resources we do develop must be reliable, secure and diverse but we also must protect the environment. Be the stewards that we are directed to be. Enhance the state's economy and protect the public health and safety. All within the context of achieving the AB 32 goals of greenhouse gas emission reduction.

So the state has developed an initial plan. We have defined what the target needs to be to satisfy the requirements of 2020 to meet the 1990 levels of emissions that the state produced by that time frame.

So with the consideration of future population growth and the tools that we have before us we have looked to improvements in the transportation sector as a significant portion of the emissions reductions. We are going to be relying more heavily on efficiency measures and

improvements to the electricity and natural gas sectors. We are going to be looking at ag and forestry as a means of helping us with GHG emission reductions.

But there is a gap that you can see here that we not fully yet defined that we will have to be addressing in the future. And to the extent that we can identify measures, whether they be more aggressive implementation of things we're already doing or new methods, that we are going to have to fill that gap if we are to be successful.

So that is the context that Chapter 1 provides for the rest of the policy recommendations. If there's any questions I'd be happy to answer them. If not I would like to invite Mike Jaske to discuss the electricity chapter.

DR. JASKE: Good morning. My name is Mike Jaske, I'm a staff member of the Energy Commission.

As you no doubt understand this chapter is sort of an overview of the electricity issues. It provides a framing that individual chapters for efficiency, renewables and distribution systems follow in more detail.

This presentation attempts to be faithful to the spirit of the text but with 60 pages of text it is hard to translate that into a few pages of overheads.

I am going to cover six topics. These are the major topics of the chapter. There are some minor ones that I will not mention in any detail. Some of these are familiar, have been part of previous IEPRs or preceding reports that the Commission has issued about the electricity sector over its many years of planning cycles, but some are new. Scenario analyses, portfolio analyses and resource adequacy for POUs in particular.

Let me start with the scenario project. This was designed to provide a better understanding of those actions that might be needed to achieve major reductions in greenhouse gasses. Lorraine had a stylized chart indicating the nature of that challenge.

The basic purpose of the project was to flesh out alternative ways in which major GHG reductions could be achieved, to understand the consequences of those at some level in terms of fuel use, costs, et cetera, so as to better

understand what sort of tradeoffs might be feasible.

The report clearly suggests that this project provided a useful way of looking at the future world. And rather than scenarios examining the uncertainties of fuel prices or other things that are the more traditional focus of planning studies, that this exemption of policy options helps give a context to the balance of the IEPR process.

Within the scenario project there were 13 scenarios assessed. They are laid out here, explained in more detail in the chapter. Essentially these set the stage with some baseline scenarios then begin to sequentially examine high energy efficiency, high renewables and the combinations of those.

I should also point out that these were run both for California and for the rest of the west. And as I will highlight in a few bullets, but the report in the chapter itself and in the staff reports in much more detail. There's significant interaction between California and the rest of the west and the degree to which each of those sort of sub-areas -- pursuing these measures

can have significant influence on the other.

This is a very high-level summary of the composition of the resource mix for each of the cases, the 13 cases I mentioned before. You can read the detail in the report but let me emphasize that the progression of the cases from left to right in this chart and the relative size of the component segments, of the bars, gives you an idea of how electricity is being generated either within the state or imported from outside to serve load in California.

In these analyses in this particular chart you can see that the level of the bar is constant across all of the cases. That we're treating energy efficiency in rooftop solar PV as applied side resources here against a constant demand.

This project did not examine other aspects that would be useful to examine such as electrification of industrial processes or electrification of transportation that would obviously increase the level of demand. That's for future work either by Commission staff or others.

The bars here -- excuse me. The

segments on the bars are sequenced in the same manner across all the cases. The ones that are constant across the bottom are because those resources are essentially constant, hydro, nuclear and the imports that California has from out-of-state plants that it owns or has long-term contracts with are essentially fixed in those three bottom segments.

The natural gas, the shaded green bar, gives a clear idea that this is the swing fuel as various preferred resources are added in greater and greater degrees at the top of the bar. So the shaded blue are geothermal and wind, the more prominent of the renewables. The pink is the efficiency and the yellow is solar PV. And last but not least that brown color at the top is imports. And you can see how imports fluctuate from one case to another as the attractiveness of those resources and their low cost cause them to be dispatched to serve California load.

How dos that translate into the GHG way of looking at the world? This chart appears in the chapter. It indicates with the sort of fan diagram portion of the chart on the right hand side how all the various cases move through time

from 2009, the first year of analysis, out to 2020, which was the year I was showing you in the previous chart.

The two black dots with the sort of bar between them are the range of 1990 values, one developed by the Energy Commission staff and the other, the preliminary one, identified by ARB two months ago. Since that issue is not yet fully resolved we have shown it as a range.

There is also on the left hand side of the chart a history that indicates a gradual increase in GHG emissions for all those power plants serving California load, whether within the state or external. But also a great deal of fluctuation from one year to the next because of hdyro availability, because of changes in the economy, whatever. A combination of all those things show quite a lot of volatility in year-to-year GHG emissions.

And of course from the big picture perspective, many of the scenarios create results which return GHG emissions to 1990 levels or even below. So I think the upshot of this way of looking at the analysis is there are a variety of options that could be pursued in order to return

the electricity sector to 1990 levels should that be the decision the ARB makes in 2008.

ASSOCIATE MEMBER GEESMAN: Or perhaps even to take it below 1990 levels should the ARB look to the electric sector for a disproportionate contribution to our AB 32 goals.

DR. JASKE: That's correct.

PRESIDING MEMBER PFANNENSTIEL: Mike, would you just say, the measurements, the units that you're using are short tons and I know that the ARB has tended to use metric tons. What is the relationship?

DR. JASKE: A short ton is 2,000 pounds, a metric ton is 2,204 pounds. For purposes of the staff's analysis we always did our work in short tons. And we have converted the inventory values, either Energy Commission staff or ARB that were originally put out in metric tons, into short tons. We can convert back to metric tons for the final report.

PRESIDING MEMBER PFANNENSTIEL: All right. But these are consistent units?

DR. JASKE: That's correct.

Among the cases. And these are just the ones which are those which California decision-

makers can pursue, not relying upon the decisions of state regulators or other planning agencies outside of California. So the three efficiency cases, the renewables case and the three combined cases. This chart is intended to show relative cost-effectiveness.

So we have the costs of implementation, in this case in year 2020. We have the instate emission difference, the ratio of those two. We have the total change in California responsibility emissions including changes in remote plants and market purchase imports, and then the ratio of that larger GHG value to the cost. And these give you a rough idea of bang for the buck.

What is interesting is that the energy efficiency measures using the costs that come out of the Itron potential study from which we derived almost all of our instate efficiency assumptions, actually are negative. Meaning that the pursuit of those energy efficiency cases is a net reduction in costs to all rate payers. Renewables Case 4A, in contrast, has a net cost. And in the combined cases, of course combing a cost reduction and a cost increase, are in-between.

SO in conclusion, the scenario project

helps to frame how to look at issues for the electricity sector. It doesn't answer questions directly. It provides clues as to how to pursue other more detailed studies. We're hopeful that ARB in its process and the joint Energy Commission-PUC process can benefit from this project.

We believe at least a joint ARB -- excuse me, a joint Energy Commission-PUC follow-up process which the PUC is funding is making some use of this analysis. Energy Commission staff will be considering taking on some additional analyses itself outside of this IEPR cycle.

Clearly as I indicated before the change in the market purchase imports, that portion which fluctuates hourly, daily, monthly, even up to a one or two year time horizon, that has strong fluctuation and has major consequences for California responsibility aversion of emissions. And that needs to be considered in any implementation of AB 32 goals.

And finally the major penetrations of energy efficiency or renewables that were merely assumed in this project require much more detailed program design, costing, and should they go

forward, implementation efforts.

A second portion of analysis prepared by the staff, the subject of two workshops, was portfolio analysis. I have a couple of slides here that summarize the way in which portfolio analysis is characterized in the chapter. The Committee is describing it as a way to understand risks in the light of uncertainties. That this is essential to informed decision-making.

There are a variety of perspectives, the individual utility perspective, the individual load-serving entity and then larger regional and statewide perspectives that have to be evaluated. An example of what that means: There is clearly an uncertainty that an individual load-serving entity has about what customers it is going to pursue so there's an uncertainty and therefore a risk to various decisions they might take.

But from the next higher level that load is merely being served by someone else who is a different LSE or some set of LSEs. So from a statewide perspective there really is no uncertainty about that load at all. So that's an example of a difference in perspective and how an uncertainty at one level is not necessarily an

uncertainty at a different level.

The chapter points that while there are differences among utilities, and that they should be understood and acknowledged, there is no reason that certain common uncertainties should be assessed differently for each of the utilities involved. And this is the case at this point in the IOU filings at the PUC in the LTPP proceeding.

For example, different characterizations of fuel price risk or fuel prices variation. That variation is the same across all the utilities. The translation of that into cost consequences for an individual utility are different but the range of fuel prices themselves should be common.

Lastly, there were a number of sort-of case studies reviewing what is going on elsewhere and it is clear that there are some useful practices being conducted in the Pacific Northwest and elsewhere that should be considered for California.

The portfolio analysis should not merely address those things that can be readily quantified but tackle, no matter how hard it may be, those risks and uncertainties that are important. And there has been a tendency to shy

away from things that are hard to quantify. That needs to be overcome.

The chapter suggests that the Commission sponsor workshops to develop an approach which is suitable for application at the PUC. The CEC and the PUC should together cooperate in implementing that in the next or in some future LTPP proceeding. The PUC should revise its procurement process to incorporate the results of this portfolio analysis. And that the Energy Commission itself should encourage the POUs to conduct comparable studies to showcase them in future IEPRs.

So portfolio analysis is another way of framing the issues that the Committee chose to emphasize in this chapter and has directed staff to pursue this technique in the future.

There is a section of the chapter dealing with issues of conventional resources, of course natural gas, coal and nuclear. I'll very quickly summarize a few pages of the chapter.

For natural gas, despite its advantages relative to coal and nuclear, the chapter says the utilities are over-committing to natural gas and therefore are increasingly vulnerable to gas price

changes. This is, of course, part of what a portfolio analysis would attempt to understand, quantify and rectify.

For coal, given the SB 1368 restrictions and the Committee's judgement about the poor prospects for advanced coal, in the time frame of 2020 utilities should not be emphasizing coal and should be looking to other choices.

Finally for nuclear. Given the state's nuclear waste laws and other barriers the Committee doesn't believe that nuclear power plants can be relied upon for the 2020 time frame, no matter how attractive they are from a carbon reduction perspective. And California should continue to be, as it has been in the past, an active participant in any of the issues associated with waste repository, waste handling, waste movement.

The chapter outlines a number of particular issues that come together for Southern California. The uniqueness of the issue, because of the location of a number of older power plants along the coast that use once-through cooling who are now subject to restrictions, greater restrictions than in the past because of US EPA

and California State Water Control Board rule making. The air quality limitations have always been very tough in Southern California through the South Coast Air Quality Management District and other agencies, and the combined consequences of these environmental pursuits constraining the ability to add conventional resources.

The chapter emphasizes that the PUC should allow the IOUs to procure new, long-term capacity to allow for the orderly retirement or repowering of those plants. There simply has to be some slack in order to allow the down time for repowering should that make sense and to assure that reliability is continued.

The work that was presented by the Commission staff on retirements and repowering was only a first step. The ISO has launched a study, the Water Quality Control Board itself has launched a study. All of these entities need to come together to complete the analysis of options for repowering or replacement or transmission upgrades to allow remote replacement so as to actually get past the analysis stage and on to action.

For the first time in this IEPR cycle

the Energy Commission undertook an analysis of POU resource adequacy. AB 380 required the CEC to report to the Legislature on individual POU progress toward resource adequacy. Staff prepared a report that assessed 54 different POUs ranging from LADWP, the largest, all the way down to entities that we were hardly aware of. Little entities that sometimes are hardly connected to the overall grid even, and everything in-between.

Some of them are subject to the requirements of the California ISO if they're in the ISO control area. Many are not and in effect are under the broad direction of AB 380 to be resource adequate but left to them to identify precisely what that means.

So a review of a wide range of sizes and situations for these 54 POUs. In general staff found that these entities were aware, they were cognizant of resource adequacy. They were pursuing it according to their own lights. And in aggregate and almost in every case individually they were resource adequate.

CPUC COMMISSIONER BOHN: Can I ask question just to interrupt for a minute? When you say generally they are resource adequate.

Relative to the big ones what exactly do you mean? Do I take that to mean that of the top five, six, four, whatever the right number is, that their current resource is adequate up through any projected time period that is used in this report?

DR. JASKE: I think I could summarize their situation as being at least out a few years. Virtually every one of these POUs has sufficient resources to cover their load. So their planning practices, their procurement practices, are in effect to be much more fully covered than has been the practice of the three IOUs or perhaps of a number of the ESPs under PUC jurisdiction.

They of course have less uncertainty to deal with. They generally have captive customer bases so there is that element of uncertainty that they don't have to deal with. And perhaps just as a style of practice the POU community has tended to be more fully committed with resources than have been those under PUC jurisdictions.

Because of the requirement that AB 380 provides that the Energy Commission report individual utility progress, I believe it's the intent of the Committee to ask the Commission to endorse a Committee version of the staff report

and conversion of the staff's draft report into a Committee version is underway.

And because AB 380 requires that this be an ongoing process and staff acquired some of the information from POUs in sort of an ad hoc manner and now our data collection regulations have been approved by OAL. We will be using those data collection regulations to get data from POUs for future Integrated Energy Policy Report assessments.

One of the projects the staff undertook was the cost of generation project. It has done this from time to time.

As a result of this particular cycle of the project staff improved its modelling capabilities, developed the tool that it uses to bring together all of the very numerous assumptions about not only the individual, technical and cost features of individual generating technologies but also the financial framework in which to evaluate and identify a levelized cost whether from an IOU, municipal or merchant perspective.

For example, cost of money, discount rates et cetera. Staff developed a report,

conducted a workshop and has now as a result of the changes or the suggestions and comments made finalizing that report now there were some key uncertainties that could not be addressed in this cycle.

Principal among them being the change in cost or performance through time. So the report focuses on recent or contemporaneous costs. It does not attempt to say how those costs may change through time.

And because of the run up in costs that are widely reported in the Trade Press, wind turbines costs because of the competition for wind turbines around the world et cetera, it's not clear how those costs will change. And there's a definite research element necessary to get a handle on that issue.

And the report did not outline how all of these various generating technologies would fare with a range of fuel prices. Although the modelling tool is capable of doing that.

So the Committee and I think this is one spot where I'm attempting to interpret language of this section of the report, supports the use of the model but doesn't support a blanket

endorsement of the results procured by staff.

There may need to be some tweaking of the words in the final committee draft. And as I said staff has been directed to address these technology, development issues for the next IEPR cycle.

The last segment of my presentation this morning has to do with long-run, demand forecasts. Of course this has always been a major cycle of the biennial proceedings. Forecasts are received from IOUs, POUs, ESPs and from staff.

A workshop was held in July about a draft, staff forecast and comparison with some of the others I've mentioned.

A number of the issues that were identified at that workshop are similar to those of previous cycles. So the staff was directed to prepare revised forecasts which is just now being completed and documented. Staff hopes to issue it this week.

And this time that has transpired between July and now has allowed a number of these issues to be worked through. Hopefully, for the improvement of the results, also in the documentation of how energy efficiency fits into

the forecast.

This is a very stylized graph based on the July forecast. You can see from a broad perspective the forecast then and also the revised one being documented now is an extension of the broad trend of historic data and a very similar picture on a peak-wide basis, on a peak-demand basis.

So as I said the staff is finalizing this work now. It has responded at least in part to stakeholder concerns. It has improved the way in which energy efficiency programs and standards are characterized.

Importantly it includes the new DOF projections that were released in June or July of this year which in the broad aggregate doesn't change population around the state. But it does have some significant regional differences.

And from a methodological perspective the forecast is more geographically dis-aggregated than was the draft forecast released in June which should provide better opportunity for those who use the forecast to make use of pieces of that rather than just the broad regions used in the past.

There will be a review and comment period for this forecast. And the Committee expects that this will, the final forecast will be adopted in parallel with the IEPR itself.

So I am now finished. And I am available for any questions from the Committee.

PRESIDING MEMBER PFANNENSTIEL: Are there questions from the dais? I have some blue cards. Most of them specified specific chapters. A few did not. But I do have two people who would like to speak or ask questions on this chapter, both of whom are on the phone.

We have Angela Haren from the California Coast Keepers Alliance.

OPERATOR: I'm here and your line is open.

MS. HAREN: Yes I'm here. Can you hear me?

PRESIDING MEMBER PFANNENSTIEL: Yes we can. Please go ahead.

MS. HAREN: Thank you, good morning. I'm Angela Haren, program manager for California Coastkeeper Alliance. The Alliance is a coalition of 12 water people programs from the Oregon border to San Diego and we've been working closely with

the State Water Board on implementation of the Clean Water Act, Section 316b regulations.

We've also been working to encourage collaboration among all the agencies with direct jurisdiction over and interest in once-through cooling including the State Lands Commission, the Ocean Protection Council, the CPUC and California ISO.

The 2007 Integrated Energy Policy Report is an important opportunity for the Energy Commission to help guide policy that will both alleviate the environmentally devastating impacts of once-through cooling and encourage modern and more efficient power generation.

As you are aware the State Water Board is expected to release policy on implementation of Section 316b regulations in January of 2008. And the Energy Commission has a unique knowledge and expertise and plays an important role in how once-through cooling issues are resolved.

In the past the Energy Commission has contributed detailed and helpful information regarding once-through cooling. For example, the Commission's letter submitted in September of 2006 regarding the State Board's scoping document and

proposed policy on the 316b regulations.

In that letter the Energy Commission states that the State Board's proposed policy is an opportunity to integrate our state's environmental policy goals for improving marine and estuary ecosystem help with the policy objectives for modernizing our coastal power plant fleet.

We also note that the Energy Commission is currently in a unique position at a really important time to insure that both of these goals are met.

And in the last year since the Commission wrote that letter to the State Water Board there has been notable progress regarding the state's once-through cooling and including a significant appellate court ruling that was mentioned regarding the illegality of the US EPA's existing 316b regulations.

Yet the current section in your draft Integrated Energy Policy Report addressing once-through cooling is only two pages long and it doesn't reference much of the progress and work being done by all of the agencies involved.

So today we respectfully ask that you

expand the section on once-through cooling to include more detailed information that will help guide the State Water Board and other agencies involved towards a progressive state policy that will protect our natural resources and improve our state's energy supplies with cleaner, more efficient production.

So in closing I ask that you also refer to the letter that we submitted last Friday regarding the Integrated Energy Policy Report for more details. And I would just like to thank you for the opportunity to comment, especially via conference call. So thank you very much.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much for your comments. Also Livia Borak from the San Diego Coastkeeper.

OPERATOR: Ms. Borak your line is open.

MS. BORAK: Hi, my name is Livia Borak and I'm with San Diego Coastkeeper. We are an environmental, non-profit in the San Diego area and our goal is to protect the region's watersheds, bays, beaches and oceans for our members.

I would just like to reiterate what Angela Haren said about the importance of

(indiscernible) and its report for (indiscernible) the state in developing uniform policy and for providing their expertise with this to the Commissioners with that (indiscernible). And we respectfully request that you expand and elaborate all the OTC sections. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Commissioner Geesman do you have a comment?

ASSOCIATE MEMBER GEESMAN: Yes. Since the Committee posted the draft the staff has published its Environmental Performance Report and there's a quite detailed, and I think quite good, discussion of this issue in the Environmental Performance Report. And I think that what we ought to do consistent with the recommendations of these two commentors is review the Environmental Performance Report for items that can be then transferred into the final IEPR.

PRESIDING MEMBER PFANNENSTIEL: We will do that. I also have Rob Anderson from SDG&E who said he would like to comment on all chapters. So I assume that means this one also.

MR. ANDERSON: Thank you and good morning. I promise as I comment on each chapter I'll try not to repeat what I said from previous

chapters.

PRESIDING MEMBER PFANNENSTIEL: Good idea.

MR. ANDERSON: First we would like to commend the Committee on this report. It's always an exciting time when an IEPR comes out. And I'd say from our company's viewpoint there's a whole lot to like in this particular report.

We will be filing comments, later this week written comments. But for the most part you will see those are pretty minor, factual corrections that we'd like to see in the report here and there. Although there are a few policy issues we'd like to raise.

I just wanted to let you know the reason why SDG&E or SoCal Gas was not here yesterday wasn't due to a lack of interest. It's just that when we went through those chapters we didn't find anything of such magnitude that we felt we needed to raise an issue. So it wasn't a lack of interest. Once again it was we don't have any issues with those chapters.

First comment I'd like to make is one of the things we believe the IEPR is about is policy for the entire state. And we saw in the first

chapters as well as throughout other chapters what we believe is some separation between how that policy ought to be applied to both the IOUs and some of the POUs.

And we believe if it's an overall policy for the state it ought to be implemented equally by both groups. And there shouldn't be some separation as to how that's implemented.

Secondly, it's a little bit in this chapter but others we appreciate the Commission's continued endorsement for the need for transmission. We think that is one of the major areas if we are going to achieve our renewables goals, even get our reliability up. It's going to take more transmission than what we're getting built today.

And lastly there's, in our view, just a little bit of an inconsistency that we see in the report. This first chapter talks about doing a portfolio analysis. You can point to a comment San Diego has made about resource plan is now become somewhat of just filling in a bunch mandated boxes. And the way I read the report you didn't think that was the right way to go.

But yet as I read numerous other

chapters of this report it either expands the number of boxes I'm going to need to fill or pre-specifies exactly how to fill it in.

So we'd like to see some consistency adopted on those points. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Is there anybody else who would like to speak to Chapter 2. Please come to the podium.

MR. GULIASI: Good morning Commissioners, Les Guliasi with Pacific Gas and Electric Company. I just have one question or comment to make about the use of the forecast in this chapter and how it's carried through in other reports and other parts of the overall IEPR.

There's still some ongoing work as I understand that is taking place with respect to the demand forecast. And frankly I'm a little bit confused about some of the results.

Dr. Jaske in his concluding slide indicated that there will be a new staff demand forecast issued perhaps this week and an opportunity for review and comment. I'd like some clarification about that process.

And the reason I'm asking for the clarification is because the forecast that is used

we think may have errors or there's some confusion about how energy efficiency is counted.

The results of the forecast are used in various places. The forecast is sort of carried through various chapters in the policy report itself.

It has implications downstream, at the CPUC and a long-term planning proceeding. And it has implications for AB 2021 work. I think it's important that we resolve whatever confusion there may be with the demand forecast.

So I guess as a starting point I'd like some clarification on what the process might be and the opportunity to address some of these issues that frankly you may be familiar with because they've been an ongoing discussion from the July workshop.

PRESIDING MEMBER PFANNENSTIEL: Mike you want to talk to that a bit?

DR. JASKE: As I indicated before the demand forecast is now in the documentation stage. The numbers are finished. I believe they have actually been shared with PG&E and some of the other stakeholders.

We anticipate issuing a report this

week. It'll presumably be accompanied with some sort of a notice about a comment period.

And as I understand the Committee's intentions it was to receive those comments, consider what they say and then make reference to some level of adoption of the report or the results at the November 21 business meeting.

MR. GULIASI: Thank you.

ASSOCIATE MEMBER GEESMAN: Les am I correct? Your primary issue and the issues that we've been focussed on in the forecast since July relate to what energy efficiency measures are included in the forecast and which ones are not.

MR. GULIASI: Yes.

ASSOCIATE MEMBER GEESMAN: Are there issues beyond the energy efficiency area?

MR. GULIASI: Not that I'm aware of. I think that's the principal issue. And if I'm not correct on that we will clearly indicate what other issues we have in our written comments.

ASSOCIATE MEMBER GEESMAN: I think the staff intends to try and clarify to the maximum extent possible precisely which efficiency measures it has included in the forecast and which ones it has not in hopes of trying to attract some

fairly detailed commentary back as to whether that approach is the appropriate one or not.

And then when we come together on the 21st of November to adopt the final report we'll also be adopting a forecast and whatever resolution of those efficiency accounting questions we can make.

MR. GULIASI: Thank you very much. Commissioner Pfannenstiel I have a question for you just about today's process. I have some general comments that I'd like to make about some of the issues pertaining to implementation of AB 32.

And I have some other specifics. But I'm wondering what might be the best time to make those general remarks.

PRESIDING MEMBER PFANNENSTIEL: I think the more general remarks probably now. Unless you wanted to save them for the end of the day. But I'll leave that up to you.

MR. GULIASI: OK, I guess I can make them now. Let me just preface what I'm about to say by with something I said yesterday for the benefit of those of you who weren't here.

I don't really want to take up a lot of

air time today delving very deeply into these subjects. We will file very extensive written comments.

And my goal in the comments will be to outline as specifically as possible and in as great detail as possible our concerns and the reasoning behind our concerns and specific recommendations for changes to the report be they changes is tone, changes in context or actual wording changes.

So please pay attention to our comments and I know this Commission has a habit of carefully reading written comments. And I appreciate the work you put into and the careful consideration of what parties have to say.

And let me also preface my remarks by saying that once again you have an excellent report. One that you can be proud of. And one that deserves recognition by the state. And the staff has done an outstanding job once again.

PG&E fully agrees with the way you framed this report by highlighting the important impact of global climate change, greenhouse gas emissions as the context for this report.

PG&E is a utility that is committed to

be a leader in the climate change effort. We were the first investor-owned utility to support AB 32. And we've been a long-time investor in energy efficiency and clean, electric, generation resources.

PG&E's portfolio for greenhouse gas emissions is among the lowest in the country. We're about 60 percent less in our CO2 emissions compared to the average utility in the nation.

And we're involved in research on emerging, renewable technologies. I want to read you a quote if I may. Investment in low and zero-emission electric generation and other technologies is critical. Policies should lower barriers and create incentives for investment in renewable power, nuclear power, advanced coal technologies with carbon capture and storage, distributed generation, advanced transportation options such as plug-in electric hybrid vehicles and other low and non-emitting technologies. Driving investment in these technologies along with aggressive for energy efficiency and demand response will reduce greenhouse gas emissions, enhance and improve the efficiency and reliability of the nation's energy infrastructure, create

economic opportunity for American business, reduce reliance on imported fossil fuels and support overall, US energy independence and security.

Now with some minor wording changes perhaps talking about the state of California instead of the United States that quote I believed could have come right out of your report, your IEPR Report.

That quote that I just read happens to be testimony from Peter Darby, the chairman and CEO and president of Pacific Gas and Electric Corporation, PG&E Corporation, which he made before the Committee on Environment and Public Works before the US Senate hearings on examining global warming in the power plant sector this past June.

So I think that quote summarizes PG&E's commitment to working very hard and diligently and taking a leadership position dealing with this important challenge we have.

While we agree with the way you've framed the report and we agree with many of the statements in the report, in the 257 odd pages we can't agree with every statement. We can't agree with every recommendation or conclusions. But

there is very much that we do agree with.

The comments that we are submitting on Friday will, as I said before, outline very specifically where our concerns lie and be as specific as we possibly can to make recommendations for changes to the report.

We do have some concern with the way that you've discussed the implementation of AB 32. Our concerns lie mainly in perhaps tone. What we wanted to make sure is that this report isn't interpreted as being overly prescriptive.

You make some strong recommendations. And I understand why you make those recommendations. That's in fact, you're charged to make recommendations. The concern is that they're going to be maybe overly prescriptive in certain respects and may pre-judge the outcome of proceedings that frankly are in some cases just underway.

You're aware of course that there is the joint CEC, CPUC proceeding to deal with the amount of rulemaking. It's important that that work is coordinated and that your agency participates actively along with other stakeholders in the process.

And so basically we're worrying a little bit that too much weight might be given to certain recommendations or judgements that you make in the report.

And I ask you just to carefully review the comments we make and the specific places that we point where our concern with respect to perhaps a little bit of overly, prescriptive language in the report.

I can just give you a couple of examples. There's a whole section around page I think 82 or so that talks about using energy efficiency to reduce greenhouse gas emissions levels. There is no question that energy efficiency is our most promising resource for obtaining GHG emission level reductions.

But it may be that your view of how much energy efficiency we can actually achieve may be too optimistic. So that's just one example.

I know you've also relied very heavily on the notion that achieving 33 percent or beyond that level of renewable resources is another way to achieve greenhouse gas emissions. There's no question that the more we do on energy efficiency, the more we do on renewables will help to achieve

those important targets or exceed those targets.

But we just caution you not to be too optimistic or overly optimistic about what's feasible. So, again, we'll try to point very specifically where our concerns lie and explain our reasoning more fully and to the extent that we can offer you some changes to the language or the tone to express those concerns.

PRESIDING MEMBER PFANNENSTIEL: We do look forward to those comments. I think that we have attempted to be factually based throughout this report. And so if you find that we have gone from fact to hope in some of the areas please point them out to us.

MR. GULIASI: We'll do that. But I can't help but comment on the word facts. I guess from a philosophical what is a fact? That the important work that Dr. Jaske just illuminated, the portfolio analysis, the scenario analysis, they contain facts. They contain information that is factually based.

But when you get into, you know, creating scenarios for a future world those future worlds rely on judgement. They may be factually based but they contain assumptions. They make

there are certain modelling conventions. They frame issues. But they don't necessarily determine outcomes.

So, again, I take your remarks seriously that to the extent that we can identify various specific facts that we disagree with we'll do so.

PRESIDING MEMBER PFANNENSTIEL: That really is the point I think of our open process. Is to try to get input to the models all along. We've had a number of opportunities we add there are assumptions or modelling conventions that don't seem to be ones that you would agree with. We wanted it all along to be open to that.

MR. GULIASI: Yes. Thank you. I understand.

CPUC COMMISSIONER BOHN: I concur with Chairman Pfannenstiel's comment. Commenting on the emperor's wardrobe is always a risky business. But it's vital to the process. And I encourage to be as forthright as you can be.

MR. GULIASI: And we will be.

ASSOCIATE MEMBER GEESMAN: I would encourage as much of a focus on the 2020 time frame. We've tried to orient the staff analysis to that nearer term perspective rather than the

2050 which tends to lend itself more to sloganeering or good thoughts.

But if your comments would place their primary emphasis on what strategies are available to the state between now and 2020 I think that would be most useful.

MR. GULIASI: Okay, we'll do that too. Thank you very much for your time.

PRESIDING MEMBER PFANNENSTIEL: Thank you Les. Others for this chapter ?

MS. CHANG: Good morning Commissioner, Audrey Chang from NRDC. I apologize. We submitted a blue card but it must have gotten lost somewhere along the way.

PRESIDING MEMBER PFANNENSTIEL: Well I do have it but it said that you wanted to talk about Chapter 3. So that's why. I already got one.

MS. CHANG: Oh, I submitted two cards. Sorry about that. One got lost along the way. I just wanted to start out by saying that we will be submitting more detailed, written comments coming this Friday.

But just a few first I guess general comments about the draft report and then I'll

address some specifics about Chapter 2.

First, overall we commend the staff and the Committee for their hard work over the past year plus. For really working and developing this draft report.

We appreciate and wholly support the overall focus on meeting the goals of AB 32. One suggestion that we have would be to more clearly highlight the key recommendations for policies or programs. Just because I know that's one of the key things that people, including ourselves, will be looking for.

Specifically on Chapter 2 I'd like to echo the previous comments made by PG&E on the need for the clarification of what exactly, what energy is incorporated into the main forecast.

I was very happy to hear that the staff will be issuing a revised forecast this weekend. We look forward to reviewing that forecast.

Commissioner Geesman you mentioned that the distinction that will be made or that will be made will be with regards to the efficiency measures that are included or not in the forecast. It would be, I'm not sure if this is already intended, but it would be helpful to, if at all

possible, indicate the relationship between those measures that are included or not in the forecast compared to those that the energy efficiency savings goals that have been set by the PUC and also for the POUs as well.

A second sort of general comment for this chapter and also actually for the entire report is that we noticed one thing that Commissioner Pfannenstiel you already noted, the inconsistency or the use of both short tons and metric tons. We definitely support the conversion to use metric tons consistently throughout the report.

Another point that we noticed just in making sure that consistent terms are used throughout the report. In some areas of the report carbon and carbon dioxide are used interchangeably in terms of looking at metric tons and measurements. And we just want to make sure that that, that the reports are gone through with a fine-toothed comb just to catch those distinctions.

With regard to the scenario analysis we definitely commend the staff for undertaking this ambitious effort. We support, in general, the

conclusions reached by the analysis. We think it's a good starting point for other analysis that will be performed by other agencies in the AB 32 implementation process.

One caution that we have is that we shouldn't, and I think the report does highlight this as well, that we shouldn't rely too heavily on the exact numbers and the conclusions from that analysis as there are certain limitations including the cost of generation, report assumptions. We definitely support the update of the cost of generation report.

Finally we support the recommendations made about portfolio analysis and the recommendation that the CEC work together with the PUC to implement aspects of the portfolio analysis for the IOUs in their next long-terms procurement proceeding.

ASSOCIATE MEMBER GEESMAN: Let me say with respect to that last point, I'm not satisfied with the progress we've made in this cycle on that subject matter. And it was an effort to correct deficiencies which your organization and UCS had pointed out to us in the 2005 Report.

And just as an observer of the way

things around these large bureaucracies I doubt that we're going to make adequate progress in the 2009 unless your organization and the Union of Concerned Scientists and others choose to really make a major investment in holding our feet to the fire in pushing that analysis forward.

A lot of methodological issues, a lot of planning criteria that really require pretty careful debate and consideration, that can't really happen unless there's active participation from a multiplicity of parties, not just the state bureaucrats.

MS. CHANG: I appreciate that and we will do our best. As with all organizations I think struggle with dealing with the assignment of limited resources. But I definitely hear you on that.

Thank you for the opportunity to comment and again we'll be submitting more detailed written comments.

PRESIDING MEMBER PFANNENSTIEL: Thank you Audrey. Others on Chapter 2?

MR. VONDER: Hello, I'm Tim Vonder with San Diego Gas and Electric Company. Good morning. As Mike Jaske pointed out the forecast that's

included in your report here, the demand forecast, is preliminary in nature and is currently in the process of being revised. And will be included in the last report or the final report.

The way I read it the schedule will not really permit us to have another workshop between now and then. And so, in effect, this is probably the last time that I will get to stand before you and make comment.

We do intend on providing written comments. But this is the last time that I'll have a chance here to say a few things.

So I would just like to make a few points and ask that you be sure to consider a few things as you receive and read staff's demand forecast and the final report.

Chapter 2, Demand Forecast mentions that staff has been trying to detail and cull out of their models how much uncommitted DSM or future EE is included in their forecast.

And I'd like to ask you to when you receive that and read it to recall back to the July time frame when we had our last workshop. And staff made a presentation and put up some graphs and charts and the utilities did too.

But in the graphs and charts that staff did put up and present it was such that utility forecasts were compared to staff forecast. And you could see at that time that when that comparison was made the utility forecasts did include, did include, all uncommitted EE and staff's forecast we know that there's some in there but we didn't know how much.

But if you go back and take a look at those graphs and charts you'll see that our forecasts paralleled quite closely staff's forecast. Kind of implying that there's quite a bit in there and ours reflect all.

So I just wanted you to keep that in mind when you take a second look at what's going to be in that report.

The other thing I'd like to comment on is Chapter 3, Energy Efficiency Targets. I guess that chapter is coming up. But in that chapter what's discussed is the AB 2021 and setting efficiency, or determining efficiency targets for the state and the utilities.

And in here, I think it's page 101 and 102, is defined three different levels of potential that can be achieved.

And the first level is technical which means that whatever is technically possible this is the level of savings that's out there in the marketplace.

And that which is cost effective is that subset of what's technically possible. That subset being the savings that can be achieved when costs equal benefits. But yet there's really no incentive for the general public to go out and do everything that is cost effective.

So there's that third level which is what they call market or achievable cost effective. And that's with a certain amount of incentives you can encourage the public to go out and do some of these things that are cost effective.

I believe in AB 2021 it's mentioned that the amount of EE that we should seek to achieve, or strive to achieve, should be that which is achievable which is that third level.

So in this Chapter 3 all throughout the chapter it talks about achieving that third level, that which is achievable. But when you come to the recommendations I believe it's on page 107 or 106 one of the first recommendations is that we go

after 100 percent of the cost effective which is actually that second level, that level that is just above what is achievable.

So I'd like to just bring that to your attention. We kind of think that the level that that recommendation should stress that what we should be achieving is that which is market or achievable cost effect not just a 100 percent cost effective.

So, those are my comments.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much. Anybody else on Chapter 2?

MR. CHEN: Cliff Chen, Union of Concerned Scientists. Thank you very much commissioners for the opportunity to comment. Just a brief couple of comments on scenario analysis and portfolio analysis.

On scenario analysis I would just request that the final IEPR Report commit to further exploration of the effect of increased penetration of preferred resources on reducing natural gas prices.

As numerous studies of clean energy policies on both the state, regional and federal level have shown that this effect is indeed

significant.

And I'd also share NRDC's concern and caution against relying too heavily on scenario analysis results to inform other state greenhouse gas modeling exercises.

Because some of the assumptions, particularly around the cost of generation assumptions, in our opinion are not very well conceived. In particular the assumptions for solar generation and for concentrating solar power are as much as two times higher as what we've been seeing from the RPS solicitations and from these projects developed elsewhere.

And they also run against the grain of the current expectation that the cost for CSP technologies will decline over time.

And I think if you correct those assumptions in the future, the greenhouse gas cost effectiveness metrics that Dr. Jaske showed for the high-renewables scenarios will be much more cost effective than the $50 to $150 range per ton.

On portfolio analysis I would like to strongly agree with the draft IEPR's conclusion that the long-term procurement planning process should explicitly incorporate portfolio analysis

techniques.

Commissioner Geesman, your charge to more fully participate in that process is definitely taken to heart and I'd like to commit UCS to helping refine those methodologies and those assumptions to the extent that we practically can.

Thank you very much.

PRESIDING MEMBER PFANNENSTIEL: Thank you. More comments specifically on Chapter 2?

MS. WHITE: Just a point, Chairman. Southern California Edison has asked to make a presentation on the overall document at the end of the day. So they do have some comments on the electricity chapter, they are just going to reserve their time until later.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. MULLER: Good morning commissioners I'm Phil Muller on behalf of Mirant America. I noted my comments on item number three on the agenda which happens to be Chapter 2. So these (laughter) will be my only comments today.

I'm here to talk about the transition from the existing power plant fleet into a future

world which is in the report is just listed as the issue in southern California which I think could be simply summarized as, there's no way we can get rid of all these generators without rebuilding the whole transmission system if we move them out of the area.

And that's something that Mirant is well aware of. In fact, PG&E is finding the same thing doing an analysis in the ISO context for the Bay Area plants, that they would have to spend hundreds of millions of dollars in new transmission. And they're not even sure that would be enough to provide reliable service.

So these old jalopies do serve a useful purpose in California. And I want to note three components that need to be considered in order to facilitate a timely and reasonable transition.

And we will be providing written comments on this Friday of course. And the first thing we note is to acknowledge the legislative support for repowering of these plants through AB 1576. And indeed, currently there's a current proceeding at the Public Utilities Commission where Mirant and other parties are sponsoring a proposal for implementing AB 1576 so that these

plants can be repowered and replaced in a timely and cost-effective manner. And we hope to see something out about that fairly soon.

And a second issue is a balanced consideration of repowering and replacement when looking at transmission projects. A lot of, in Dr. Jaske's report he talked a lot about we can only retire so many of the megawatts in Southern California with this much transmission upgrades.

Well the question we need to evaluate is, where is the most cost-effective and the most responsible balance between that? We all know that building large transmission infrastructure is surprising even more difficult than building new generation in California. And obviously it would appear to be easier to repower, replace and renew generation at existing resources than it would to build large transmission infrastructure to reduce the amount of local resources required.

And we would hope that the balance between these two would be fairly and equitably considered in any policy that's put forward.

And finally I have to give a plug for support the reinvigoration of merchant generation in California. Now I know it's become an

unpopular topic. The Merchant model works best as we've seen in the past at basically wringing the costs out of generating electricity.

And right now the only way you can build power plants in California is with a long-term contract with a utility.

Now that provides, of course, for ratepayer financing for the cost of the generation. And it also takes that merchant incentive to wring the costs out of the equation because once the contract is in place you have an agreement that specifies how much you get paid for doing what you're doing. And any benefits you may make from wringing costs out go directly to the pocket of the generator which is not a bad thing. As a representative of a generator I can say that.

But there's also less opportunity for the ratepayers to benefit. And in a merchant model where the merchants take the risk of the market and basically provide the best product they can at the lowest cost to consumer because that's what they have to do in a market in order to survive, a reinvigoration of the merchant model would allow that to occur.

But that cannot occur as long as most of

the generation that's out there is relying on long-term contracts with guaranteed, basically guaranteed returns. You can't compete with somebody whose already got all their costs covered by ratepayers.

So to that end we would support and hope that this commission could also support development of a capacity, market mechanism or some other comparable mechanism that would provide a means for independent generators to participate in the market and to take their risks and to basically provide the benefit that we feel we can really effectively provide that you do not get from rate-based generation resources.

So our comments will focus on that. And we look forward to where we go from here.

PRESIDING MEMBER PFANNENSTIEL: Thank you, we look forward to your written comments. Other comments on Chapter 2? Let's move on to Chapter 3. Thank you Mike.

MS. WHITE: Michael Messenger is going to be making a presentation on the Committee's Chapter 3 related to energy efficiency and demand response.

MR. MESSENGER: Good morning

Commissioners. My name is Mike Messenger. I work here at the California Energy Commission on the staff.

My charge is to summarize the contents of Chapter 3 and to respond to any questions you may have.

The first slide just talks about the scope of Chapter 3. There's basically five separate sections that I'm going to highlight here.

The first one is sort of summarizing a little bit about what Dr. Jaske has already referred to, the use of different levels of energy efficiency to reduce GHG gases.

The second is there is an analysis of different programs and approaches to achieve the goal of all cost-effective energy efficiency. And I'll have some discussion about that.

Third is there is an analysis of potential savings on some recommended policies with respect to building and appliance standards.

Finally there's an analysis of potential savings from demand response policies and different types of program options with some estimates of the savings that could result from

that.

And finally I'm going to try and summarize the Committee's recommendations.

I'm not going to spend a lot of time of this chart. I'm basically summarizing some material that Dr. Jaske went over earlier. Basically we're trying in this analysis look at the impact of different levels of energy efficiency and renewable resources either alone or together on GHG emissions throughout the entire western region as well as the state of California.

And there's some valuation estimates of the cost and benefits of different levels of funding and what it would cost in terms of dollars per ton of carbon reduced.

From my perspective the key results of that analysis with respect to energy efficiency is that they showed it was possible that higher levels of resource displacement by energy efficiency and renewables could actually result in disproportionately higher level of GHG savings relative to the electricity sector's current share of GHG emissions.

And secondly that it matters what's happening in the rest of the nation. And in

particular the rest of the western region. If you look at some of the high efficiency cases you can get a 25 percent reduction in GHG emissions in California and similar levels throughout the western region at a cost of something like $36 dollars per ton.

And then the final result I thought was interesting. Is that the energy efficiency levels were, as you would expect, when you get higher levels of energy efficiency you always get a lower level of GHG reductions.

There weren't any cases where you were essentially pushing out non-carbon generation resources. There was always some residual carbon left in the system. So we didn't reach the point where we were starting to get to a place where energy efficiency was no longer affecting carbon emissions.

The second section of the chapter has to do with the Committee's charge to identify all potentially cost-effective, energy efficiency in AB 2021.

With respect to the comments from the gentleman from San Diego I think it's important to understand that the AB 2021 requires us to

identify all potentially achievable cost-effective efficiency resources by 2016 not simply all achievable.

So we're supposed to strive to go beyond where we are now. And we spend some time both in this chapter and later on in the staff report talking about how we will bridge the gap between essentially current efforts, and current forecasts of program savings and what we need to do to get to that potentially achievable level.

In this process that publicly-owned utilities have submitted annual savings targets which we calculate to be equivalent to meeting 67 percent of the all economic potential identified by their consultants over the next decade.

We note parenthetically the IOU saving goals adopted by the PUC will achieve roughly 71 percent of the economic potential quantified in the Itron study.

So our charge, and I'll go through it this in more detail when I get to figures three and five on the next chart here, is to bridge the gap between something like 70 percent of economic potential to 100 percent over the next 10 years.

The Committee after reviewing all the

evidence presented by both staff and various parties at the proceeding decided that we should adopt what we had labelled as Option 3 in the staff report. A statewide goal of achieving 100 percent of the economic potential identified for each service territory.

And this is equivalent to roughly 39 thousand gigawatt hours and 6800 megawatts of additional savings by the year 2013.

And the Committee made it very clear to us that we should in our report tell each utility that they are responsible for working with staff and other parties to fill the gap between all economic potential and current plans by working with other stakeholders including local governments and state agencies to identify additional programs or further ramp up their own programs.

ASSOCIATE MEMBER GEESMAN: Mike, this question of economic potential between the IOUs and the POUs. What discount rate is used in determining economic potential?

MR. MESSENGER: I believe in the Itron they used the weighted cost of capital for the relevant utility. And the RMI I think tried to

extend that practice to the POUs when they estimated economic potential for the POUs.

And that's different from the discount rate we generally use here at the Commission which is three or four percent real depending on the proceeding. Because we are looking at things from societal's perspective. And the reasoning behind the Itron study is this is a utility investor and they need to look at things in terms of their, the utility's cost of capital which they calculate to be equivalent to the weighted cost of capital.

ASSOCIATE MEMBER GEESMAN: But does it make any sense for us to embrace that particular perspective in the duties that AB 2021 have assigned to us?

MR. MESSENGER: In this particular case I think it's a strategic call of whether you want to try to work with the consulting firms doing this analysis to try to redo the analysis using a lower discount rate and see if it makes any difference.

ASSOCIATE MEMBER GEESMAN: Well what do you think it would result in?

MR. MESSENGER: I did some analysis like this in one particular sector. I looked at the

lighting analysis and tried to look at what you would, what different result you would get if you used a lower discount rate.

And the analysis that I did showed 12 percent additional savings that were being identified by measures that didn't meet the cost curve at, let's say, six or seven percent real and did meet the cost curve at three to four percent real.

I'm not sure if that would hold across all sectors. So it's something that we could pursue in the future. But we just didn't have enough time to redo all the analysis that Itron had done for the POUs as well as try to redo it for the IOUs.

ASSOCIATE MEMBER GEESMAN: I'm not suggesting that we redo any analysis. But I'm having a bit of a difficult time trying to reconcile why this Commission takes a particular approach in the development or building in appliance standards.

And I know the last time we adopted standards using a three percent real discount rate, NRDC came in front of us and said they really thought that it ought to be two percent.

And the Stern Commission says that it ought to be .3 percent. I don't know what the right percentage is. But I know that the Energy Commission has historically used a social discount rate of three or four percent.

How do we reconcile that policy and practice with evaluating the utility programs which use a sizably larger discount rate?

MR. MESSENGER: What I can tell you Commissioner is that we were involved in initially scoping out these potential studies. And we recommended the use of lower discount rates and were told, no the appropriate rate to use in this proceeding in this form is the utility's cost of capital.

ASSOCIATE MEMBER GEESMAN: And you want me to accept that.

MR. MESSENGER: No, I'm just reporting on the facts. If you want me to continue to go back and fight for a lower discount rate I can do that. But I haven't --

ASSOCIATE MEMBER GEESMAN: I just think it's one of the things we need to determine before we adopt the final report.

COMMISSIONER ROSENFELD: Commissioner

Geesman there's another headache which is, should we or should we not be addressing the externality of CO2? The PUC when it does its, I think, when it does its benefit/cost analysis it throws in, I don't remember, it's not a very large number, it's less than 10 dollars a ton, but it does throw in a nominal externality and we don't do that.

So I'm just joining you in the headaches. I don't know the answer.

ASSOCIATE MEMBER GEESMAN: Well the spirit of the times is to be big and bold. And I'm not even asking for either of those just to be narrow and consistent (laughter).

MR. MESSENGER: Well I think the issue hinges on the policy determinations made both here and at the PUC about what's the appropriate discount rate for whether the money that utilities spend is society's money or utility's money.

And I agree with you that we could make a case that it's society's money and therefore they should consider using our discount rate. I'm just saying that currently we haven't been successful.

ASSOCIATE MEMBER GEESMAN: Well in the new construction area is it society's money or is

it the builder's money. It would seem to me that we've addressed that over the course of the last 30 years and consistently concluded that we ought to use a social discount rate in evaluating these things.

I don't know how we could rationalize varying from that.

MR. MESSENGER: Okay, well I don't think we intentionally meant to vary from that. I was involved in developing those discount rates back when we first set the standards.

So I support you completely. I'm just telling you we have, and we can put a recommendation into the final report that perhaps I can outline some action steps to perhaps change the situation. It just hasn't been changed yet. Thanks.

Okay, this graph simply tries to illustrate the different levels of energy efficiency that were submitted by different parties in the proceeding and the ultimate goal that we're adopting as a Commission.

The black line, of course, is the baseline forecast. The pink line is simply what the IOUs and the POUs submitted as their annual

program savings forecast that they were adopting. The little dashed pink line below that is staff's interpretation that we should continue the savings beyond the year 2013 which is the last official adopted savings goal to the year 2016. We just extend the slope.

And you can see that leads to a fairly significant set of savings in the last three years of the forecast there.

The bottom line there is that the Committee weighed all the arguments and decided that the appropriate target in this case is the green square which is labelled as 39,000 gigawatt hours per year savings in the year 2016.

And that's different than the current level of forecast which are roughly 26,000. So the gap is about 13,000 gigawatt hours that staff is committed to working with both the POUs and the IOUs to try to bridge that gap to get to that additional level of savings.

And just to complete the rendition there. The blue is what was identified as the technical potential in the Itron report.

This graph simply shows the same analysis for peak. And again you can see this

gap. It's not quite as pronounced as the other one, the previous gap.

The Committee is again adopting the green square which is the cost effective economic potential which is roughly 6800 megawatts as it comes close to the baseline of, I believe, it's 5700 megawatts which is the sum of all the utilities annual savings targets.

The next square. In the Committee report and also in the upcoming staff report on AB 2021 we outline some additional approaches to get from this program savings potential to all economic. It includes the use of potentially more expansive and extensive at building and appliance standards.

The consideration of white tags where private sector entities can get credit for achieving a specific level of energy savings and perhaps use that if any types of carbon cap and trade markets emerge in the next five to ten years.

There's a consideration of different types of public/private partnerships to move the penetrations and specific types of technologies into the marketplace.

The Committee has recommended that the Commission work carefully with the Legislature to craft some type of bill that might require all cost effective efficiency investments be made at the time of sale for any change of real estate in the state of California.

And we're also going to be recommending different types of fiscal policy changes to perhaps promote the penetration of emerging energy efficiency technologies in a time frame before 2020. We're emphasizing again trying to get things moved up to 2015, 2012.

The next chapter of the report talks about additional energy savings that could come from adoption of new building and appliance standards. The report reviews efforts that the Commission has made to promote energy efficiency as part of SB 1 which is promoting obviously photovoltaic systems by requiring a certain level of energy efficiency to be installed.

We're also considering PV requirements as an option compliance tier for new building standards and trying to essentially integrate renewables and energy efficiency into the entire building standards arena.

The chapter also mentions the potential for legislation to require an on-site audit and cost effective investments at the time of sale.

There's also a review of various actions to increase the efficiency of lighting in general via programs new efficacy and/or efficiency standards and consumer education programs.

I think staff's recommended approach is AB 1109 which enjoyed the support the lighting industry and is awaiting signature by the Governor. In fact it may have already been signed.

PRESIDING MEMBER PFANNENSTIEL: Yes, it was signed by the Governor.

MR. MESSENGER: I'm not sure. It was signed, thank you. And the chapter also points out that if AB 1109 wasn't passed the Commission might want to consider the use of national and/or European lighting standards that are due in the next two years. But I think that with AB 1109 those points are moot.

The next section in the chapter dealt with demand response. I'm switching now from energy efficiency to demand response. The Commission held a couple of hearings to discuss

work by consultants to quantify the potential contributions from demand response.

These three bullets are just sort of a general summary of the findings. One, enabling technologies can respond to price or emergency signals to reduce the need for expensive peak purchases. And that's already happened in some cases in the last three or four years.

When you integrate demand response with advanced metering networks you can actually improve customer service and lower the cost of billing in addition to enabling the demand response which is the primary purpose here.

And the challenge identified in the report is to increase the level of customer acceptance of some of these new technologies and the rate structures that are needed to signal price either higher wholesale prices and/or emergencies.

We had a consultant attempt to estimate the economic or the technical economic and market potential for price responsive DR in a similar manner to what has been done for energy efficiency.

Dr. Ahmad Faroqui estimated that if we

were to deploy the best available demand response technology uniformly in places where it made sense we could lower peak demand by roughly 25 percent over the next 10 years.

They also made judgements about what was economic or cost effective from the perspective of current rates. And they found that a demand reduction of 19 percent was possible in the residential sector, seven percent in the commercial and nine percent in the industrial sector.

Finally, this firm's estimate of the market potential was that we could achieve roughly a five percent peak reduction if, and this is an important if, if 50 percent of residential customers eventually choose to be on dynamic rates. And again this is based on work done by the Brattle Group.

The Commission decided after hearing this evidence that it wanted to open a load management proceeding to consider proposals to achieve more price responsive and emergency-based demand response technologies and programs.

And in particular it was interested in three proposals discussed during these

proceedings. One the use of dynamic pricing as a default rate.

Second the requirement that utilities use programmable communicating thermostats for emergencies in retrofit applications because the Commission plans to require PCTs for new construction applications and will be effective as of, I believe, April 2009.

And the Commission also wants to consider the adoption of an automated demand response standard that might require buildings to have automated demand response equipment available to respond to different types of emergencies.

The potential benefits are described in this chapter from adopting these proposals. The estimate is roughly if all three of those proposals were adopted by the Commission in the form of load management standards there would be a 20.2 percent reduction in peak. And net present value of savings from those actions would be 11.4 billion dollars for all three proposals.

Proposal one will of course require working with the PUC to amend rate designs consistent with the AB 1x law and to allow more dynamic pricing to occur.

Proposals two and three will require utilities to potentially deploy more enabling technologies through either programs or rate designs that might require that.

So now I'm going to the last section of the report which summarizes the Committee recommendations. And some of these things I probably already said so I apologize for repeating. But I think it's important that these are the principal recommendations that need to be emphasized.

One, that staff is supposed to enlist POUs in a collaborative relationship to achieve aggressive savings goals to achieve 100 percent of the economic potential in the next decade as identified in these proceedings.

And in our report we have identified a series of meetings and workshops to try and make that happen.

They recommend that the Commission pursue legislation to require energy audits and all cost effective investments at the time of sale of all buildings in California.

To enact new appliance standards focussed on general service lighting. And I think

that is required by AB 1109, a 50 percent reduction by 2018.

We continue to work with our sister agency to get to these particular big and bold goals which are to increase the efficiency levels of building standards so that new buildings are net zero energy users by the year 2020 for residences and by 2030 for commercial buildings. Obviously that will require integration with the renewables portion of the house to make sure that there's enough on-site renewable generation so that essentially each home will not require a net energy from the grid that's built after these target dates.

We also want to investigate market-based approaches to energy efficiency such as white tags available for private decision makers who make efficiency investments on their own.

We're going to open a formal management rule making to pursue some of the demand response goals mentioned earlier. And the Committee continues to support behavioral research on customer decision making that will help to create new program approaches.

And that was the end of my presentation.

I'm open and available for questions.

PRESIDING MEMBER PFANNENSTIEL: Thank you Mike. Are there questions from the dais? Yes, Commissioner Bohn.

CPUC COMMISSIONER BOHN: What are the odds of enlisting the POUs in the collaborative relationship to achieve aggressive savings goals. I mean is there some reason that that's put in that format as opposed to sort of telling them what they're supposed to do?

MR. MESSENGER: Staff has worked, I would say, for the last five years to develop a collaborative relationship with the POUs and help them identify new sources of funding as well as new program designs.

So I would say the odds are greater than 50 percent that we will continue to work collaboratively together.

They will not like the fact that we're recommending higher goals than they recommended in this process. But I don't think that's going to be an obstacle for us to continue to work together to achieve the goals.

PRESIDING MEMBER PFANNENSTIEL: Other questions? I have a number of blue cards. People

who would like to speak or ask questions on this. Starting with Audrey Chang from NRDC.

MS. CHANG: Good morning again. I guess we will start on, well first let me say that my comments here are centered on the energy efficiency portion of this chapter.

And the question for you Mike, I guess to start out with, I'd like some clarification on what you mean by subbing the goal of 100 percent of economic potential on a statewide basis.

Does that include or is that limited to just utility programs? Or does that also include codes and standards savings?

MR. MESSENGER: That includes any or all programs that reduce the consumption of electricity in each of the utility service territories. So programs is a substantial portion of that. But we think that we need to go beyond programs to working with local governments. To working with agencies, regional agencies that can set standards.

So anything from white tags to programs to standards.

MS. CHANG: Okay. In that case then we do support that statewide goal of adopting the 100

percent of economic potential of the state-wide goal.

And I think that it may benefit from some clarification that does incorporate all sources of savings and not just from utility programs.

I think there's an important distinction that needs to be drawn between the statewide energy efficiency versus the individual goals for each utility, IOU or POU.

PRESIDING MEMBER PFANNENSTIEL: Audrey, may I just ask, what is your concern about the 100 percent economic if we did it, if we were just looking at utility programs. If we looked at, say, the Itron study and said to the utilities, you know, this is what your goal is to achieve that much.

MS. CHANG: From my understanding the economic potential includes not just savings that are achieved through utility programs but also savings that are achieved through the codes and standards, Title 24 and Title 20 --

PRESIDING MEMBER PFANNENSTIEL: So it's everything that is in the Itron study though.

MS. CHANG: -- right. So if it doesn't,

I think there's just a distinction. The utilities can help through the advocacy efforts here at the CEC to improve Title 24 and Title 20. But there's also activities that the CEC alone, I mean through the adoption of updated standards can achieve savings.

So I just think there's an important distinction and clarification that should be made.

MR. MESSENGER: I want to be really clear about this because I think this is a slightly new policy that we're adopting here. And not one that says, utilities you're responsible for your programs savings.

MS. CHANG: No, I agree. I support the statewide goal but I think when we're drilling down into targets, specific goals for each specific utility, I think it's important not to hold them accountable for those also ---

MR. MESSENGER: That's the change. Let me finish what --

MS. CHANG: Okay.

MR. MESSENGER: -- I was going to say.

MS. CHANG: Okay.

MR. MESSENGER: The change is that we're asking utilities to act in some senses as

portfolio managers.

MS. CHANG: Right.

MR. MESSENGER: And for their territory, all of their citizens and people that they serve, they're supposed to achieve savings that include both their programs and coordinate other programs, standards, whatever, so that they're responsible for achieving the 100 percent goal not just from their programs.

But they need to come the Energy Commission, let's say, and say, in 2015 we met this goal, 70 percent of it was from our programs, 20 percent was working with these other parties and 10 percent was working with the Energy Commission to achieve this standard.

So they have to have an accounting that says they got to the 100 percent even though their programs alone might not be equivalent to that 100 percent.

So we're asking them to take responsibility for their service territory. As opposed to just saying, we did our part, here's our 70 percent from our programs. Is that clear?

MS. CHANG: Yeah, I mean we definitely support the role of the utilities as portfolio

managers. I think that the savings need to be achieved through cooperation not just through the utilities but cooperation with the CEC in setting standards et cetera.

COMMISSIONER ROSENFELD: Madame Chairman I'd like to add a specific word to that. I agree with this back and forth. But the utilities do a great deal to help with Title 10 to 20 and 24. And the buzz word is case studies and that stands for code and standard enhancement.

We couldn't get along in Title 20 and 24 without the help of the utilities. And the utility program managers are complaining all the time that they don't necessarily get credit for that sort of work.

So it's codes and standard enhancements and training our building code enforces which we just have to encourage them to do.

And so I agree with what you two guys are saying.

MR. MESSENGER: Right, the difference that I'm trying to signal and maybe not doing it very adequately is, now it's going to be important to do more collaborative work from the perspective of the utilities.

Because they're going to be asked to report back to us not on just their program savings but on the savings that also occurred in their territory as a result of working with these other approaches and perhaps getting, for example, the Energy Commission to adopt a different appliance standard or a regional government to adopt a new time-of-sale ordinance or whatever.

So their responsibilities are being expanded beyond just their programs. This is the way I understand what the Committee has recommended. If I'm wrong, please let me know.

CPUC COMMISSIONER BOHN: And whose money are they spending in these programs? In other words, it seems to me by definition unless I can't get the semantics on this stuff straight anyway, but, if you are requiring the utilities to go beyond their, quote, programs and report back, they will be spending somebody's money to do that.

And so what's the difference between the utilities programs and what it is you're asking them to do. You simply overlaid another program it sounds to me.

Because you're still spending ratepayer money to get this done, I assume. You're not

spending shareholder money. I mean, whose money are you spending?

MR. MESSENGER: Well, I'm not sure and I'll try not to step in it by saying whether it's ratepayer or shareholder money. It's somebody's money that the utilities are spending.

I assume the majority of it is ratepayer. But what we're saying here is --

CPUC COMMISSIONER BOHN: So this is another program burden on the utilities no matter how you talk about it.

MR. MESSENGER: -- well, I don't see it as a program burden. What I see it as is we're asking them to do their programs and to actively participate outside of their programs in collaborative proceedings, other kinds of proceedings to get other actors to do the majority of the footwork, let's say, they're just using their intellectual capital and not necessarily spending ratepayer's money on that program. But trying to encourage that program to come up and happen.

CPUC COMMISSIONER BOHN: So you're deputizing the utilities to go out and use their intellectual capital to achieve a social result

presumable the people who are generating all of this are people being paid by the utilities and presumably the ratepayers.

So I'm having trouble semantically with this one.

PRESIDING MEMBER PFANNENSTIEL: Commissioner Bohn let me jump into this. The utilities now are given a broad mandate from the PUC to spend a certain amount of ratepayer money, a very large amount of ratepayer money, to meet certain goals. And we want to be part of that.

I don't think we're seeing this as necessarily an increment on that. We're seeing this as part of that. As their charge in the next 10 years to use that money which is somewhat deployed now to supporting us in our codes and standards, our Title 20 and 24 work.

But we're saying now, we're directing that their goals be 100 percent of economic potential. That we want them to focus their programs to be working towards meeting that.

CPUC COMMISSIONER BOHN: So, are we changing then the program? I'm having a semantic problem on this one.

PRESIDING MEMBER PFANNENSTIEL: They go

through a --

CPUC COMMISSIONER BOHN: Because if we're changing the program and imposing an additional burden, that's okay. But --

PRESIDING MEMBER PFANNENSTIEL: Well we have one change that I would point out is that under 2021 we had the obligation to set statewide goals for energy efficiency. So as part of that we're setting this goal as 100 percent of economic potential.

How do you achieve that is the question of some of it is from our ongoing codes and standards, our building standards and appliance standards. Some of it is from the utility programs that are underway.

We are proposing here that those utility programs be focussed on gaining 100 percent of the economic potential within their service territory.

Whether the existing dollars are sufficient, whether they are directed in the right programmatic areas, I believe it's something that we will be dealing with over the next 10 years.

The PUC does their program design in three year cycles. And so we need to get into that three cycle of PUC-directed spending to make

sure we can achieve the 100 percent goal.

CPUC COMMISSIONER BOHN: So this is, I'm just trying to get it straight. So this is a new, an additional factor that the CEC wishes to inject into the duties of the utilities in pursuit of this other standard. It's okay, I just want to understand it.

PRESIDING MEMBER PFANNENSTIEL: No, I mean that is how I would describe it, yes.

CPUC COMMISSIONER BOHN: Okay.

MS. CHANG: I think in that case I think there needs to be some clarification and coordination between the two commissions.

Again, taking codes and standards as an example I agree with Commissioner Rosenfeld, the utilities have been very instrumental and helpful in a lot of the improvements to the codes and standards adopted by the CEC.

However not all those savings are necessarily attributable to the IOUs. So I think there's a bit of an accounting problem in terms of what the IOUs are allowed to, quote, count towards their goals.

So there needs to be a clarification, a definition of the goals and --

PRESIDING MEMBER PFANNENSTIEL: I think it's absolutely the case that there does need to be some clarification in roles and responsibilities and in definitions.

MS. CHANG: I thought it was helpful Mike that you pointed out on your graph which the numerical equivalent of what a 100 percent of all economic potential was. I'd encourage the Commission to draw that out specifically in the text of the report, just to quantify it.

And then also explain how or put forward a way in which how the progress of the state will be tracked against those goals.

In addition, I think the goals that were recommended were put in terms of the 2016 time frame. Is that correct?

With that I would suggest, if possible, to extend that goal to 2020 since that's the time line that the PUC will now be looking at when they're in the process of updating the IOU goals as well just to be consistent.

And, of course, the 2020 time line is also with AB 32.

In addition to the statewide goal that has been set we definitely encourage the

Commission to make any recommendations necessary to make improvements on the POU-specific goals and have to explicitly track their progress against those utility targets in addition to tracking progress against the statewide goal.

I'd like to also just emphasis some other key recommendations that we've made previously in our comments on the AB 2021 Draft Report which we would like either included in this final IEPR report or the final AB 2021 report.

And we urge the Commission to include clear guidance for the POUs. On the next AB 2021 potential studies and the target-setting process as well as the SB 1037 reports and to make recommendations for improvements in the individual POU targets.

I would just also like to note that this process has been very compressed. So we urge the Commission to also make the POU energy efficiency a focus of the 2008 IEPR update to expand on some of the work that wasn't able to be accomplished within the short time frame allowed this year.

For example, we support the intent to set E&MB guidelines. It's noted on page 91 of the draft report. And that could be a part of the

IEPR update performed in 2008.

We also support the recommendations for time-of-sale efficiency requirements. And I just wanted to note to the Commissioners that we have, NRDC has submitted a recommendation to CARB as part of the scoping plan process that reflects a similar recommendation as well.

A final point. A clarification question Mike. In the graphs that you showed with the, like this one in the forecast and then the impact of efficiency, is this using the updated demand forecast or is this --

MR. MESSENGER: My understanding is that this black line represents the updated demand forecast.

MS. CHANG: Okay.

MR. MESSENGER: The issue that has been raised is to what extent are the savings that we're subtracting off of this already in the forecast. And we're working with the forecast office to try to clear that up.

MS. CHANG: Okay, great. That's great. That's one of our key concerns, so thank you.

MR. MESSENGER: Okay. I just need to say one thing because you sounded like it was

going to be an easy thing. But I want you to know it's extending the goals from 2016 to 2020 is not something we can do overnight.

And we will do it upon direction and it's not a problem. But it stretches our forecasting limits or our ability to predict out there.

And AB 2021 requires us to do 2016 so if directed we can move beyond that. But it just makes it a little bit uncertain.

MS. CHANG: Yeah, I'm not trying to diminish the amount of time and effort that it will take to do that. But any efforts that are possible will be appreciated.

MR. MESSENGER: Thank you.

MS. CHANG: And Commissioner Geesman I wanted to note just very quickly on your comment about the discount rate and as you noted NRDC has supported the use of the societal discount rate which we also had supported in the PUC's efficiency rulemaking.

But the PUC in that case had decided to use the weighted cost of capital for the discount rate. So I assumed that's why the consultants picked the Itron potential study also used that

same discount rate.

And then one clarification. Commissioner Rosenfeld, I know that you noted that the PUC in their avoided cost process, what you said is that they include externalities for CO2 and other pollution. I just wanted to clarify that's not actually looking at all sort of externalities or impacts. But it's solely looking at the financial risks of CO2 emissions and other pollutants.

Thank you very much.

PRESIDING MEMBER PFANNENSTIEL: Thank you Audrey. Cynthia Mitchell from Energy Economics Incorporated.

MS. WHITE: Commissioner Cynthia has asked to show a few slides as well. So just a moment.

MS. MITCHELL: Good morning and thank you for letting me appear here today. I'm going to wear two hats.

My first hat is as TURN's consultant on energy efficiency. I've been working closely with TURN since about 2000. And then my second hat is in my private, professional role as the principal for Energy Economics. I'm out of Reno, Nevada.

The first thing I want to do is share with you some analysis that I did for TURN this summer that was in the Commission's rulemaking '06, '04, '01 zero on the planning for 2009 to 11 and beyond.

And in your IEPR you reference the draft decision of September 27th. And what I did is with my associate looked at the utility efficiency programs, building codes and standards and did a simple exercise first just flipping.

This is now the utility program savings. And these are the building and appliance standards.

If I go back, see here you have the utility efficiency programs layered on top of your codes and standards.

If you just flip that then what you see is sort of a different perspective about the utility energy efficiency savings over time in California.

And what you get is this dynamic that since about the late 1980s the utility programs have continued to contribute some savings but it's been relatively modest.

And another way, what you see then when

you take from the year 2003 and take the existing imbedded savings, current savings, this whole block of savings here, and using the CEC's forecasting methodology just continue to forecast those savings out over the 10 years of the Commission's energy efficiency targets in each measure just like a power plant has a useful life or a longevity to it.

And this is an average 12 year useful life. What you have is that the savings as one would expect deteriorate or degrade out over time.

Then what you have here in the green block is the utility's projected savings for '04 through 2011 based on the current mix of measures in the '06, '08 portfolios.

And what you see is that, and the Commission in their proposed decision on September 27th referred to this as the treading water syndrome.

And what's happened with our utility efficiency programs is that we've gotten somewhat stuck in the short run or the short lived measures.

And that's largely lighting measures such as the screw-in CFLs. The Commission in

their proposed decision has said we've got to address this and has come up with some language and proposed actions that they hope will remedy this.

This shows the same effect but on the peak demand. And what you see that if we don't change from the current program design and market strategy which is, as I said, largely CFLs. We're going to be in a situation where not only are we not meeting the Commission's goals or the state goals but we're actually going to have less peak demand savings in the future than we did at the height of the energy crisis.

And this is back to the just the gigawatt hour. And I don't have plotted on here but the Commission's goals would are essentially serve as an extrapolation from that.

So I wanted to share that with you. If you got my handout that --

COMMISSIONER ROSENFELD: Cynthia --

MS. MITCHELL: Yes.

COMMISSIONER ROSENFELD: -- while you still got that up there. I'm puzzled because the treading water part, the yellow part, involved utility programs that were many years. I can't

read from here the time scale. But what is times equals zero.

MS. MITCHELL: Times starts at 1975.

COMMISSIONER ROSENFELD: Okay. And during that time '75 to '00 the utilities' average spending maybe 180 dollars a year and that's up now by a factor of three. And so in your right hand part I'm just amazed that I don't see a big zooming up of benefits. Because we've gone from 200 or 250 million dollars a year to 750 million dollars a year.

MS. MITCHELL: I understand that Commissioner Rosenfeld. And I was surprised too when we first started doing this analysis and did many iterations and checking of the work on it. In this, that 18,500 gigawatt hours is the Commission's 10 year energy target, I believe.

But the issue at hand is that the portfolios of the utilities are dominated by the short-lived measures of screw-in CFLs.

Beginning with quarter one of 2006 through the second quarter of 2007 the portfolios on a statewide basis are approaching 75 percent screw-in CFLs.

And the useful life in commercial

applications is any where from one to three years. And then the useful life in residential is around nine years.

And when you average that out you get to a seven year useful life.

PRESIDING MEMBER PFANNENSTIEL: But might not the issue there be not that the CFL isn't the right application but that the utility maybe should be spending their money convincing customers to buy CFLs on their own rather than buying them for the customers? And that way the useful life would be infinite.

MS. MITCHELL: Exactly. And one of the things that was I think when Audrey and Mike were talking back and forth about the utility and Mike was explaining the utilities expanded role to deliver savings from their programs as well as to stimulate greater market response.

In the Commission's decision they've talked about that as market transformation. And they want the utilities to broaden their focus and start looking at transforming markets.

And for example, the Northwest Energy Efficiency Alliance in the northwest of Washington, Oregon, Montana, Wyoming and Idaho

this summer declared the CFL market transformed.

Not that savings are not coming from CFLs but that utilities no longer have to spend money. That it's become a naturally occurring resource.

And our position, TURN's position is not that the utilities stop spending money completely in CFLs but we've got to move beyond those. And we've got to start having those CFL savings happening on their own on a naturally occurring transformed market basis.

COMMISSIONER ROSENFELD: Cynthia, I'm still confused about CFLs as is President, Chairman I think. I mean as far as I know the utilities only had $2 as incentives for CFLs and the societal savings is something like 50 bucks by the time the service life is up after you said three to six years.

How much money did the utilities spend on CFL programs out of $700 million a year?

MS. MITCHELL: I'm not exactly sure. And that's a figure that's not been readily available. I know that energy division for instance has sometimes past summer submitted data requests to the utilities to try and discern

exactly how much money has been spent on CFLs. And I don't know that that figure has been made publicly available yet.

But I do know that through the second quarter of 2007 that the total, statewide savings for the '06, '08 portfolios are running, are approaching 75 percent of your gigawatt hours are from CFLs.

And the majority of those are in the residential sector.

COMMISSIONER ROSENFELD: Okay. We need to get this straight off line I think. But go ahead.

MS. MITCHELL: Okay. I wanted to make a couple of comments about this is the figure 8 and then the figure 9. This is gigawatt hour savings and then the figure 9 is megawatts.

And let me just ask, did you all get this handout that I'm talking from? Okay. As represented in the report this is on page 96, this is referred to as yearly reported accomplishments.

And the blue bars, the actual savings, that is, it really should if you want to be I guess more factually precise you should say, utility reported savings.

Because these are savings reported on an x-ante or prior to any measurement and verification, okay. So, and it's not an insignificant point I believe.

For instance, with PG&E and Edison right here, these big spikes in 2005, let's see, this is, it's actually better to look at a peak demand basis. But these big spikes of you know not quite doubling their goals in 2005. A large part of that is the programmable thermostats in the residential sector which then we concluded 2005 and sometime during this 2006 portfolio planning process the utilities said, not a good measure.

It's not a reliable measure. And so I believe across the three electrics I think for 2005 the programmable thermostats were about 22 percent of the projected peak demand savings. So those are gone. And that was by the utilities' own you know early statement of that they weren't verifiable measure that gave, you know, retained or sustained savings.

Then I wanted to go back just a minute to the discussion. The gentleman from PG&E and then the discussion somewhat between Mike and Audrey about achievable versus cost effective.

And in the Itron study or even the energy efficiency potentials study that came prior to that, the KEMA's energy study. It's a pretty standard methodological process to do technical, economic and market achievable, okay.

The market achievable is largely driven or based on the utilities existing market strategies and program design. So when you look at a potential study and you see a significant drop from technical, economic and then to market achievable that's because it's generally picking up a lot of the status quo.

There's nothing wrong with that but we as the Chapter 3 points out we've got to move beyond sort of traditional status quo approaches to delivering efficiency.

And with the utility programs we've been limited to rebates directly to the end user or incentives to manufacturers and distributors and such. And to really harness that cost effective potential we need to be able to allow consumers to purchase energy efficiency in the same way that they pay for power plants and transmission lines and distribution systems over time in their monthly utility bill.

So one recommendation I wanted to leave with you is to support the Commission in their proposed decision where they have directed the utilities once again to get aggressive about consumer on-bill financing.

Another matter that I wanted to discuss with you briefly goes to the discussion that's in this IEPR as well as other CPUC and CEC documents about the importance or the role of energy efficiency or the relationship of California energy efficiency initiatives in keeping California's per capita consumption relatively constant.

And this summer when as part of this analysis that I did for TURN I then became curious and interested in trying to understand what is it that makes California unique in this type of really dramatic departure in the nation's per capita consumption.

And we've conducted some limited preliminary analysis just some simple regressions that show that there's really a fairly weak correlation between energy efficiency savings and this is building codes and standards and the utility efficiency programs, that there's really a

relatively weak correlation between this level of savings and then the relatively constant per capita consumption.

And the highest we could get the correlation on the R squared was less than 20 percent attributable to efficiency.

And then we did additional analysis looking at the correlation between per capita and the price of electricity and we got a much stronger correlation there of about 40 percent.

And then we've also been looking at the underlying shifts in economic structure whether and the role that changing household size in California has played.

And just an interesting aside is that as the household size for the United States as a whole has been trending downward since 1980 household size in California has gone upward. And then for the rest of your border states, Arizona, New Mexico and Texas those households sizes have also trended downward. But I think it's Texas is starting back up again also.

But anyway it's not to criticize this work but to suggest that California is unique in many ways in its use of electricity from the

United States as a whole. And I think that what I would personally like to see and this is where I've got my Energy Economics hat, principal for Energy Economics hat, because I just got this analysis complete in the last couple of weeks and TURN has not had a chance, I haven't had a chance to vet it in the office.

But what I would like to see is more complex analysis where we can control for a multitude of other factors including weather patterns to get a more complete understanding how conservation and efficiency programs have contributed to the levelling off of California's per capita consumption.

And I think that much of the data that would be required for this analysis is being collected by the CEC in its energy demand forecast. And so the extent that the Commission was interested in that I would be glad to share with them our analysis to date.

And so, yes --

COMMISSIONER ROSENFELD: Cynthia, you're quite right in what you've been saying and let me just say there's another --

MS. WHITE: Commissioner Rosenfeld could

you please repeat that and turn the -- thank you.

COMMISSIONER ROSENFELD: Sorry, I've got the mic on now. There's a paper by Jim, floating around a draft by Jim Sweeney from Stanford and an Indian student of his and let me just give you his numbers. They agree with yours.

If you look at the prop which is up there now you will see that the United States has gone up about 50 percent and California has been about flat.

If you go to the very first prop that you showed, the Energy Commission prop you'll notice that at the top that Mike Messenger and I put in that there's a 15 percent effect there. Well 15 percent is about a third of 50 percent. And that's exactly the number that Sweeney and his student get.

They agree spookily well with this analysis. They explain the remaining 30 percent which is two-thirds of the story which just the effects that you were mentioning.

And I think we never claimed, I hope we've never claimed or interpreted to saying that 100 percent of that difference is energy policy. I think a third of that difference is energy

policy just as you said.

And I can forward you the Sweeney thing.

MS. MITCHELL: That's great. Thank you. Thank you very much. And thank you for your time today.

PRESIDING MEMBER PFANNENSTIEL: Thank you for your comments. We have on the telephone Bill Walsh from SoCal Edison who wants to speak on this chapter.

OPERATOR: This line has disconnected.

PRESIDING MEMBER PFANNENSTIEL: Fine. Rob Anderson from SDG&E. Did you have something on this chapter? No. Les Guliasi. Is Les still here? Okay. Okay, I think then we move on to anybody else I should ask on Chapter --

OPERATOR: PG&E and somebody from SMUD.

PRESIDING MEMBER PFANNENSTIEL: Go ahead.

MR. BURT: I apologize for not turning in a card. But as I listen, I'm Bob Burt, Insulation Contractors Association. But as I listen I want to add some meat to some of the bones.

First of all look at our low-income energy efficiency program. Every year contractors

have not the slightest difficulty in finding lots of eligibles. So I can regard that as a kind of canary in the mine indicating that there is a whole lot more potential for residential than is indicated by some of our studies.

Which leads me to explain why some of the potential is not being realized. My members now are much more happy signing a contract with a 100 houses with a developer and having a phone guy sitting there all day working to get houses one at a time for energy efficiency.

And I suspect that that's quite common elsewhere in the contractor community. So I think it's partly a matter of emphasis and money.

But the best place that I can say to look for money is the fact that a reasonable look at the cost of capturing and sequestering CO2 indicates that it going to be at least an order of magnitude higher than the most expensive possible energy efficiency.

So this to the extent that the ARB starts requiring any offsets at all that hit the need for doing some sequestering or else finding more energy efficiency I don't think the utilities will have the slightest hesitation which they'll

do.

And where the cost effectiveness will go up. And just in our own business I can look around see all kinds of potential. For example, nearly every house built before say 1970 has empty walls. And it's not cost effective now to put insulation in those because those ugly holes that you drill in order to put in the insulation demand the extra cost of a house paint job.

But I think that that easily could be covered with a much higher cost effectiveness. And I strongly suspect that that same thing is true all through the business.

I don't know air conditioning. But I also believe that there are a lot of old air conditioner out there whose maintenance is deplorable and would probably greatly improve our peak load business if that was fixed.

On lighting transformation my wife is my expert consultant. And I can tell you in our house the only fluorescent bulbs are in my study. Why? Because she feels that Mr. Edison's product has a color that she likes. She does not like the rather bluish stuff that comes out of all of the offered product that is much more efficient and

some that are maybe hidden in the back.

So my thought on market transformation for lighting is, let's make sure that what's sold has colors in output that the women will like. Otherwise you're not going to sell it because who runs the house? Not the man.

I agree with the comment on discount rate. And I note that it is very important but my earlier comments were calling for some IOU investment. Obviously the IOU discount rate would be what would apply there.

The other comment I would offer is that if we can get more efficiency I observed looking at some other states by having a lot more standard offers. Because those seem to jump out at people and be a lot more easy to sell.

With that I'll close my comments and ask if anybody has any questions.

COMMISSIONER ROSENFELD: I have a slight comment to praise you. I think you've kind of suggested a nice utility program. The utilities ought to perhaps consult with the home painting, with the house painters and get out the word that that will be a good time in which to install insulation in your open-cavity walls.

MR. BURT: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you Bob. Other comments on this chapter?

MR. BEEBE: Good morning Commissioner, I'm. Yeah, my name is Bud Beebe. I'm with the Sacramento Municipal Utility District. And I just thought I'd take this opportunity as an erstwhile laggard in the publicly-owned utility communities to note that this summer our rate setting body, our board of directors has adopted a demand side, that is and energy efficiency program that's 50 percent greater than that required by AB 2021.

And we're not alone in the POU community. I know that the POUs really do get it. We are very closely coupled to our customer consumers. And we know that we can save money by saving energy. And we are aggressively going after the energy efficiency piece that's out there.

That noted I'd also like to note that publicly-owned utilities like SMUD, like others I'm aware of are, should not be confused with local governments that can do things like set energy efficiency standards for buildings and

other very important pieces in the land use planning and so forth.

Even where POUs are not are ostensibly a part of local governance, which SMUD is not, we they're not necessarily aligned with those parts of the government that can affect building standards and so forth.

I think you get my meaning there. And that is that for instance at SMUD we are a local district. We do not report to any other local government, not Sacramento City, not Sacramento County, not Placer County of which we serve some customers.

So just to not confuse publicly-owned utilities with local government in general. Thank you. Any questions?

PRESIDING MEMBER PFANNENSTIEL: Thank you very much. Other comments on this chapter? Yes.

MR. ASLIN: Hello, my name is Richard Aslin and I work for the Pacific Gas and Electric Company where I head up the economics and load forecasting group. And I had really one clarifying question and then just a couple of comments.

So the clarifying question I had was to follow up on the question from the person from NRDC with respect to these graphs three, five and three/six.

It might be easier to see them if --

MR. MESSENGER: Like the light level to go down?

PRESIDING MEMBER PFANNENSTIEL: Would you dim the lights in the room.

MR. ASLIN: So if I understood Mike correctly he was saying that the top line, the black line is the updated load forecast. It's not the draft load forecast.

MR. MESSENGER: It's my understanding, yes.

MR. ASLIN: And it's my understanding from talking with staff that what's, the plan is that they won't be changing the forecast per se but what they will be doing is changing the characterization of the forecast so that currently the forecast is characterized as not including any effects of uncommitted energy efficiency. And there will be some language to the effect in the final California energy demand and, I would assume, carried through to the final IEPR that the

forecast actually does include some significant portion of the current target levels of CEE or uncommitted CEE programs. That's my understanding. It that your understanding also Mike?

MR. MESSENGER: The characterization of whether it's significant or not is still being debated. But your characterization I think is correct that the, in terms of the lines that will change, the black line won't change, the top line there.

But there's potential that the slope of some of these lines might change if we jointly decide that some significant portion as you said of the committed DSM is already in the forecast.

Because that would then suggest that it's not a straight one-for-one subtraction. Is that clear for you?

MR. ASLIN: Yes, so if I could just make sure I'm totally clear on that. So the line for example, the pink line that now says and I guess I'm developing near-sightedness here as much as far-sightedness is that says 19,000 gigawatt hours. But that would be something less than 19,000 gigawatt hours.

MR. MESSENGER: It would be something less if we decide there's a portion of the uncommitted DSM that's in the staff forecast, yes.

MR. ASLIN: Okay, I just wanted to clarify that. Because the time, the turn around time on the written comments is pretty brief. So we're drafting them right now.

In terms of the other comments. One thing is I would like to see in Chapter 3 a discussion of the standards versus programs that's maybe a little easier for the layman to understand.

Right now I'm having difficulty understanding how the potential studies treated standards. My own understanding of that is that they treated the standards as being set throughout the forecast horizon at a certain level and not changing.

Then in the discussion of targets versus programs I'm confused as to whether it's all encompassing very much like the discussion had we had just a few minutes ago. Whether it's all encompassing or whether it's just utility programs and how that all works out.

So I think it would be beneficial for

all stakeholder groups to have more clarity around exactly what is the distinction in the setting of the targets around standards and how that evolves during the forecast period.

The last thing that I would like to comment on is just to give a pitch for something that we might want to think about in the 2008 update of the IEPR. And that is to consider that the demand forecast that is currently out there does not include any of the potential impacts on customer energy usage over global climate change.

So it's, I think it's reasonable to expect that as we encounter global climate change over the next few decades that what we will see is that customers, at least potential for increased energy usage both at the peak because of air conditioner use and in energy itself will be increasing.

And that increase could be very significant. There's been a lot of studies done by the California Climate Change Center. At least two that have been published recently and they both indicate that there would be a very material impact on energy usage in California due to global climate change.

So I would just say I think that would be a very good thing to think about in the 2008 IEPR update. And Les is back so I'm not sure whether he had any comments.

PRESIDING MEMBER PFANNENSTIEL: Thanks Rich. Les did you have any comments on this chapter?

MR. GULIASI: No thank you.

MR. ASLIN: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Any further? Now it's moving on towards noon. The next chapter, the renewables chapter that we're going to take on is going to be, I believe, another one that will have a fair amount of discussion around it. So my suggestion is that we break now and then come back in an hour and pick up on the renewables chapter.

MS. WHITE: So we'll reconvene at 12:45?

PRESIDING MEMBER PFANNENSTIEL: At 12:45, yes.

(Whereupon, the lunch recess was taken.)

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AFTERNOON SESSION

PRESIDING MEMBER PFANNENSTIEL: The other Commissioners I believe will be joining us. But we have a full afternoon so why don't we start with Chapter 4, Renewables.

MS. WHITE: Thank you, Chairman. Bill Knox will be providing the presentation on Chapter 4.

MR. KNOX: Good afternoon and welcome back from lunch. I have the dubious distinction of being the first after lunch speaker today.

Dr. Pam Doughman and I did most of the drafting of the renewable resources chapter under the thoughtful direction of the IEPR Committee but we also relied heavily on some other staff reports, specifically the Intermittency Analysis Project final report, the Strategic Transmission Investment Plan, and in addition the scenario analysis and two portfolio analysis projects as well. And we had a lot of work together with the electricity office in putting things together for this chapter. Pam couldn't be here today as she is teaching back in Illinois, public policy.

The scope of Chapter 4. I think I'll cut right to the chase here and say that one of

the big parts of it is answering the question, is the 33 percent renewable portfolio standard goal by 2020 feasible? I guess I'll go right to the answer to that. We think it is feasible but it ain't easy. It's going to take a heck of a lot of work and it's going to take people working together. And it is going to take investment in infrastructure and it is going to take changes in program structure.

This presentation doesn't follow the same order as does the chapter. We kind of look at the 33 percent feasibility first and then go to the barriers and the recommendations. But I am going to start like the chapter does with the key drivers.

Of course as mentioned earlier this morning, Lorraine pointed out with her graph that about 28 percent of the GHG emissions in California are due to electricity. So of course electricity is a major, is going to play a very important role in reducing greenhouse gas emissions to 1990 levels.

And it is also important to note that renewables is a mandate in and of its own and it has many other benefits besides GHGs And

renewables should not create offsets that can be traded. Tradeable offsets would be for anything in addition to the goals that are set.

The other main thing besides reducing greenhouse gas emissions is managing risk and cost to ratepayers. And we're looking on the one hand at economic risk. And there is significant economic risk in a business-as-usual scenario relying primarily on conventional fuels, specifically in the area of unknown future costs of fossil fuels, natural gas in particular, on which we're 42 percent dependant at present. But also the extra costs associated with carbon emissions production.

There are also serious environmental risks that can be mitigated through increasing the percentage of renewables in the statewide portfolio of generation. And these environmental risks are not only those associated with global warming but also health risks associated with burning fossil fuels.

What are the barriers to reaching that 33 percent goal and to increasing, significantly increasing our renewable energy? The biggest one is lack of adequate transmission. Another one

related to that is the challenge of integrating intermittent resources into the mix.

A third sort of physical barrier is there is currently a shortage of turbines that is causing wind turbines' cost to go up. And related to that there are barriers to repowering wind that are both economic barriers that are discussed in the chapter and there are also permitting barriers to repowering wind. There will be a consultant report coming out on this within the next month or so as well.

Programmatic barriers. Need for more transparency, less complexity in the program. And in addition a more full valuation of renewables with respect to their competition. And again it needs to be clear that those emissions displaced by the RPS should be taken off the top of any trading program for allowances or emissions reductions credits.

And finally some legislative barriers. Currently there is no legislative authority to require renewable procurement from either POUs or IOUs beyond the 20 percent goal in 2010. And in addition some of the earliest formulations of a potential federal renewable portfolio standard

could adversely impact our own goals because they could lead to the potential for double-counting of benefits.

Our recommendations generally kind of follow ways to get over the barriers. First of all, of course, building transmission to renewable resource areas and more on that a little later. Improving the transmission and distribution systems to accommodate intermittent renewables as well as distributed generation and demand response.

Our third recommendation has to do with feed-in tariffs. Recommend implementing a 20 megawatt feed-in tariff essentially now as soon as we can at the MPR, the market price referent for renewable energy.

And to begin a process with our sister agency, the CPUC, together to consider the possibility and potential of feed-in tariffs for larger scale renewable projects.

The fourth recommendation: The market price referent has just recently taken a major step that's improved it, which is the incorporation of a greenhouse gas adder. And that has increased -- This is not in the chapter

because it happened on October 4 but essentially it increases the MPR by about a little less than a penny per kilowatt hour depending on whether you're looking at contracts starting right away or far into the future.

But the MPR could still be updated to better reflect the risk associated not only with fossil fuel prices but the other areas of risk as well. But fossil fuel prices are probably one of the largest and most unknown risks.

Fifth, coordinate the RPS with a cap-and-trade system. Again, this is taking any RPS required emissions reductions off the top before cap-and-trade allowances or emissions reduction credits are figured and allocated.

And then finally, ensuring that as the federal government moves closer to perhaps a national standard for renewable energy make sure that that doesn't in any way effectively make it difficult for states to have meaningful standards that are above a federal minimum standard.

Much of the renewable resources chapter addresses the questions raised in AB 1585, which was legislation passed in 2005 that would have required the Energy Commission in the 2007 IEPR to

address the feasibility of 33 percent renewable by 2020.

Now this did not actually become law because it was tied to SB 107 becoming law in 2005. In fact that was delayed for a year. But the Governor's signing message directed the Energy Commission to incorporate the answer to this question of feasibility into the 2007 IEPR.

And so specifically we have done so as directed in the areas of transmission, dispatchability and reliability. Taking a look at the 2006 LTPPs, long-term procurement plans. The impact on rates and also looking at the current status of the RPS.

Again I want to say that we relied very heavily on the strategic transmission investment plan, which has a section specifically on transmission for renewables, although in general other transmission improvements are also going to improve the system to the benefit of renewables as well as other resources.

We note that some of the key projects do face delays. Tehachapi, which is probably necessary to meet our 20 percent goal appears to be delayed until 2013.

There may be some delays in Sunrise Powerlink due to continued discussions of the best path. Green Path, the municipal utilities, IID, there are also some questions about the speed with which that is moving.

At the same time that there are delays in these projects that are in fact moving forward there are good causes for optimism in the ability to bring on transmission towards the 33 percent goal. Particularly we look forward to the results of Edison's and PG&E's studies of transmission. In the case of PG&E from the Northwest and for Edison we're looking at transmission to renewable resources it owns both in California and in Arizona and Nevada.

We are also encouraged by FERC's support of a new category for transmission and new ways of cost allocation that will be realized when the Cal-ISO implements its tariffs that are supported by the declaratory order accepted by FERC.

We also believe that we need to continue to look into feed-in tariffs and a potential role for the California ISO in feed-in tariffs. And this is analogous to the role that Transcos in Europe sometimes have in bringing in renewables in

ways that are equitable for all load-serving entities.

We are also encouraged by a number of ongoing instate planning processes. The RETI or CRETI, I think it's still referred to as CRETI in our chapter, encouraging work towards programmatic EIRs for renewable resources. And then some work needs to be done as well looking at the Cal-ISO queue.

Not exactly transmission but related, deliverability and RECs. I just want to point out that to the extent that RECs are used it does reduce or it can possibly reduce the need for transmission if RECs are determined to be allowed to meet a percentage of the RPS goals.

For more and additional information on recommendations with regard to transmission for renewables and other resources as well be sure to see the strategic transmission investment plan as well because we have drawn a lot of our thinking from that.

Dispatchability and reliability. This is another question of feasibility. The intermittency Analysis Project Final Report did come to the conclusion that based on a scenario

that they projected for 2020, a specific scenario, that 33 percent renewables can be incorporated provided the appropriate infrastructure are in place as well as technology and policies made to facilitate use of that infrastructure. And that the integration will also require investment in the transmission and generation and in operations infrastructure and changes in operations practice, policy and market structure.

And again, cooperation among all regulatory participants is required in order to successfully improve the transmission and distribution system to accommodate the state's greenhouse gas goals.

The chapter takes a brief review of the 2006 LTPPs, the procurement plans of the major utilities that are still in process. I understand that the Phase II Decision is expected probably by December.

The plans as far as I know to date show a lot of uncertainty about meeting 20 percent and that seems to be tied to the development of the transmission. Unfortunately they also do not seem to be on track in general to the 33 percent renewables goals. But hopefully as the process

unfolds and we're taking steps in that direction.

What about the impact on rates of 33 percent renewables? It is really difficult to answer this kind of question because there are tremendous unknowns both in the cost of renewables but also in the cost of whatever renewables are competing against. You know, a more conventional scenario, it's really unknown what the cost of that unconventional scenario will be as we have an increasingly peaky load with population shifts and so on.

However, there are a number of reports that have sort of addressed to some extent what would the impact be. And one of them is the Center for Resource Solutions' report prepared in 2005 for the CPUC which saw, which analyzed the cost of 33 percent. And they saw a small increase, I think it was .57 percent in rates through 2020 but a net savings through 2030.

Now things have changed since then. The cost of steel has gone up and so this study, as any study is, is out of date within a year. It is difficult to predict the future.

A more recent study prepared as part of the IEPR process, the scenario analysis which was

explained by Mike Jaske earlier, does show a cost increase of somewhere in the neighborhood of $10. There are a couple of different potential sort of baseline scenarios. There is Case 1 which is sort of now, 2006. Case 1A is getting to the 20 percent goal.

But at any rate it is important to realize that when you look at that scenario analysis that's -- the costs there are not just costs that go into rates. There are also societal costs. In particular for example, the cost of PV are only somewhat subsidized to the extent that the public goods charge in utility programs have costs that support the SB 1 goals.

However much of those costs are also borne by the customers, commercial and residential customers that are expected to be putting in PV systems. So those costs need to be separated in the scenario analysis in order to look at the impact on rates.

The other thing is starting from Case 1, that includes incremental costs to meet our current 20 percent goals. So if we're looking really at just the cost to go from 20 percent to 33 percent I think what the scenario analysis has

to say is that there may be a minimal impact on rates.

But I also want to point out that not all transmission costs are captured and that there is likely to be higher transmission costs to reach renewable resource zones than there would be to have new conventional fuel plants if we were not carbon constrained.

There is another analysis that also attempted to look somewhat into costs. this was a Portfolio Analysis Draft Report which was published I think back in June and it looked at only costs of generation. And it attempted to be illustrative of the cost, illustrative of the effect of incorporating risks into your cost analysis.

Now there are a number of caveats with this report. This report unlike the scenario analysis did not attempt to look -- unlike the IAP did not look closely at transmission and integration constraints and did also not look at dispatch of power. Furthermore it didn't really look closely at where and what amounts of each renewable technology can be incorporated into the system.

And then finally there's a caveat just in terms of the methodology. It is very difficult to constrain the future variability of costs and also the co-variance between different costs. If steel goes up does fuel go up with it or does it go in the opposite direction? I think in that case they go in the same direction but there are some of those questions that are difficult to understand.

There's also structural changes that are leading to changes in the cost of fuel and those weren't modeled in this report. Rather it was based on historical volatility and looking at the risk of volatility.

But given those caveats the findings, the most important finding I think was that there are portfolios of generation that have greater than 33 percent renewables that seem to have the potential to reduce risk and cost and greenhouse gas emissions at the same time.

Another finding is that an optimal generating portfolio is going to include the technologies that have higher stand-alone costs. A stand-alone look at costs is not a good comparison.

And then finally adding non-fossil fuel fixed cost technology to the extent that the OMN costs are quite small and there is no variable fuel cost. Adding those to a risky portfolio is likely to lower total costs at any level of risk.

And this is just an illustration of the portfolio analysis model given its caveats. And the little yellow dots in here, the yellow dots show California 2006 but assuming carbon value at $20 a ton, which is what is common in Europe as I understand.

And then also there is a 2020, which is a projection of kind of business-as-usual, which I don't believe even takes us in this particular case to the 20 percent renewables goal.

But that curve shown between Mix P and Mix Q is what is known in portfolio analysis as an efficient frontier. And that's the locus of points at which for any point there is not another portfolio at lower risk that has the same cost and there is also no portfolio at lower cost that has the same risk level.

You can see that the business-as-usual portfolios do not lie on that economically efficient frontier. Again I think that this is

just a first stab at looking at portfolio analysis. Many of the assumptions that were brought into the other analytical projects have much more depth and breadth to them so there needs to be a merging of the different analytical styles' methodologies.

I am going to finish up just looking at where we are right now, essentially, in RPS compliance. How far are we towards the renewable goals.

Statewide we have increased renewable energy. The left hand axis, the Y axis shows that in just total production renewable energy is going up but as a percentage of total generation renewable energy is really about the same as it was back in 2002.

We are a little bit higher than this in 2006 in terms of the actual defined goal, which is generation divided by retail load, and we're more at 11.9 percent on the RPS standard itself. But we have a steep ways to go both to get to the 20 percent goal and to the 33 percent goal. It's even steeper trying to get to 20 percent by 2010, but as mentioned earlier, the LTPPs and I think in general people are concluding that we are not

going to be there until a little after that.

This is the progress of the three big IOUs so far. And this is just delivered energy. This is delivered energy from 2001 to 2006 as a percentage of retail sales.

San Diego has made the most progress starting from furthest behind. Edison has made a little progress but it doesn't look good lately. It has been going downhill since 2004. I think load is increasing faster than renewable energy. PG&E did a little, made a little bit at first and then kind of flattened out.

But we are hoping that the fruits of the contracting activity between 2002 and 2007 will be seen in the future and will get us back on a trajectory towards that 33 percent longer term goal.

This is a snapshot of contracting activity, not necessarily approved by the CPUC yet but advice letters filed based on our contracts database, which is available on-line. And as you can see there has been a tremendous amount contracted, especially in the last couple of years.

And these are based on the dates that

advice letters are filed so it's a little bit different way of looking at it than as seen in the quarterly report prepared by the CPUC which I believe looks only at approved contract. Whereas we're including -- And again also there's been quite a bit of progress since August '07 and I think we'll try to incorporate that into the final version of this chapter.

What about the rest? The IOUs are responsible for about 70 percent of the retail load and the rest of that is about 25 but sometimes more than that. The POUs, you know, there are variations year to year and then about 5 percent the ESPs.

The POUs between 2003 and 2006 have seen a three percent increase in RPS deliveries. So they are moving faster although they started quite a ways behind the IOUs. LADWP increased from 1.6 to 3.9 percent, SMUD increased from 4.8 to 10.9 percent. We don't have the increases for Imperial and Modesto but we are seeing them at around six and two-thirds.

So the POUs have also made a lot of progress in contracting as well and we hope to see that bear fruit in the next few years and

especially in the coming decade moving up to 2020.

ESPs are lagging the furthest behind. APS has gotten up to 4.8 percent, the others range from about .8 to 2.4 percent.

And that concludes the analysis. Again I would like to say that we do tend to be optimistic. I need to be optimistic. I have kids and they say, can we really get all this renewable energy? My kids are teenagers now. And I say well, you know, it's not going to be easy to get to 33 percent and it is not going to be easy to reduce carbon emissions but I think that we still have to try. And I think we all have to work together and that makes it possible. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much, Bill. We have a number of --

CPUC COMMISSIONER BOHN: Can I ask --

PRESIDING MEMBER PFANNENSTIEL: Of course.

CPUC COMMISSIONER BOHN: I'm sorry.

PRESIDING MEMBER PFANNENSTIEL: Commissioner Bohn.

CPUC COMMISSIONER BOHN: Can I ask a couple of questions?

MR. KNOX: Sure.

CPUC COMMISSIONER BOHN: What is the thinking behind separating out the RPS from any allocations of greenhouse gasses? You're getting two different ways to get kind of the same result aren't they?

MR. KNOX: Well I think that they are two different ways. And I think that the thinking behind AB 32 is that there are both essentially mandatory and regulatory ways of achieving emissions and there are also market ways and that we're going to need both of them.

And from what I have seen -- I am not as familiar on this as Pam Doughman is. I don't know if she is on the telephone lines, there is a possibility. Anyway, but I'll try to answer this to the best of my ability.

Just reviewing some of the AB 32 implementation thinking, and particularly the Market Advisory Committee report. As I recall, they make the point that things that are mandated that are going to be happening anyway as a requirement are not going to result in the production of tradable emission certificates. Because if that were to happen then one utility could essentially reach its mandate and then sell

its emissions credits to another utility but that sale would not produce any new greenhouse gas emission reductions.

DR. DOUGHMAN: Bill, I'm here. Can you hear me, Bill?

MR. KNOX: Pam, do you have anything to add with that, Pam? Did you catch my --

DR. DOUGHMAN: Yeah. I think, I think you cast it well. The goal is to maximize the impact of the renewable energy in the RPS program on the 33 percent by 2020. Maximize the impact of those, of those programs on greenhouse gas reductions.

And we looked carefully at a report put together by the Market Advisory Committee looking at recommendations on how to design a cap-and-trade type of system to help implement AB 32. And that report recommends a combination of regulatory and market systems, watching carefully to see how they interact.

And they said that especially for changes in technology that a regulatory program might be more effective for that goal and that the market-based trading system is more effective for other types of changes needed to reduce greenhouse

gas emissions. Does that answer your question?

CPUC COMMISSIONER BOHN: It answers the question, I'm not sure I'm persuaded by the logic. If you order somebody in an RPS situation and you mandate certain allocations, my understanding of any kind of a cap-and-trade system is that it is based on a series of mandated allocations. The RPS was an early stage.

And I am not arguing one or way or another, I am just trying to understand that. As I understand the recommendation, whatever the cap-and-trade system is, it is therefore to be imposed on top of the RPS standards as opposed to integrated into the cap-and-trade system. Is my understanding correct?

DR. DOUGHMAN: Yes.

MR. KNOX: Essentially that's right.

DR. DOUGHMAN: The recommendation.

CPUC COMMISSIONER BOHN: Okay. The next question. You talked about earlier, improve the MPR to reflect greenhouse gas and I think you said, and other risks. What other risks do you have in mind that are relevant or useful or can be used by a market price referent?

MR. KNOX: I think primarily what we're

looking at is the risk of fossil fuel volatility and/or structural increase in the prices of natural gas. And I think that that's a risk that is difficult to quantify. But there are methodologies in which you can quantify and actually economize, monetize some of that risk rather than to use a single, a single gas forecast essentially or a single snapshot of what future prices look like today to the market and to the predictors.

Rather than use that you have to say, well let's see, you know. How long are we exposed to the risk of fossil fuel prices and what do we think the volatility is going to be and are there structural elements that are likely to lead to rising prices even beyond the volatility around a point. Whereas --

CPUC COMMISSIONER BOHN: So your issue here is to put a value on the mere fact of volatility in addition to the market price referent. Volatility in itself is something that needs to go in there as distinguished from whatever the price might be.

MR. KNOX: Well I don't know enough about these models to fully answer your question

but I think that volatility itself is a risk and it is a risk that is typically quantified in a lot of financial analysis. And I think more work needs to be done to figure exactly how to apply that part of risk.

But I do think that there is a cost to that risk, okay. And I also think that there are other factors besides just volatility. Upper pressure on fossil fuel prices, particularly on the far horizon is like the lifetime of a plant that people need to do -- We still need to look into that and research it further. But there's a lot of uncertainty.

On the other hand when you have a technology that essentially most all of the cost is up front when you build it, it doesn't have that long term exposure to risk. And I think that we need to take both of those risk factors and somehow account for -- monetize them and account for them in the MPR.

CPUC COMMISSIONER BOHN: Okay. One last question. You comment here that LADWP and SMUD have done a better job of sort of getting toward the goals than the IOU has. Why? Or how, maybe.

MR. KNOX: Well, you know, that is very

speculative and I don't know. I mean, for one thing they started with less and that in itself may be an advantage. We saw the same thing with SDG&E. Starting with less it's easier to double, for one thing. But, you know, I haven't really thought a whole lot about this.

But I think also they have their own systems in which they have a lot of control. They're essentially monopolies in their own areas and they are vertically integrated monopolies to a large extent. And I think that they have an easier time contracting and planning. It is a public process because those IOUs are public entities. But it is not as big and unwieldy of a process as the process of moving forward I think for the IOUs. And that is just my own, speculative thoughts on that.

CPUC COMMISSIONER BOHN: Well what I was looking for was some guidance or some suggestions of one possible reading of that and it's unclear, I guess, from what you said. But one possible reading for that is that we have complicated the process with the IOUs unnecessarily. If the SMUDs and all can do it better and faster through different policies maybe there's some guidance

there that, you know, we could use.

I was just looking for some sense of whether or not there were some things that stuck out in this comparison where we could say gee, they can go buy what they want when they want it as long as it meets these standards, rather than all the stuff that we sort of impose on them.

MR. KNOX: I think that their contract to delivery period has been shorter. These are just observations. And I believe that also the -- well I'm not, I can't say for certain but at least for the early years of the RPS I think that those solicitation to contract periods were quite long. So again those are observations of what I believe are some differences.

You know, again I think there is an advantage to being smaller and only looking after yourself. It's all, you know, the board of the POU makes those decisions.

CPUC COMMISSIONER BOHN: Okay, thank you.

PRESIDING MEMBER PFANNENSTIEL: Commissioner Geesman, did you have a question?

ASSOCIATE MEMBER GEESMAN: No.

PRESIDING MEMBER PFANNENSTIEL: Any

other questions from the dais?

We have a few blue cards from people who would like to speak on this subject. Cliff Chen from the Union of Concerned Scientists.

MR. CHEN: Hello. Cliff Chen, Union of Concerned Scientists. I'd like to commend Bill and Pam and the CEC staff for what I think is an excellent chapter, which really does a really good job of laying out the enormous, but in our view attainable challenge of getting to 33 percent renewables by 2020.

I would like to particularly commend the CEC and Bill and Pam and staff and the IEPR Committee for introducing this concept of quantitative assessment of the risk mitigation benefits of renewables. I think this is a critically important benefit of renewables that although it has been much talked about it hasn't really been quantified. So I think this is an incredibly valuable edition to the discourse on the benefits of renewables in the RPS.

I would also like to commend the IEPR Committee and the CEC staff for developing a risk-adjusted MPR methodology that in our view much more fully reflects the value of long-term fixed

price renewable contracts. And many of us will be looking to the CEC's analytical expertise when the PUC considers broader changes to the MPR methodology next year, including a permanent inclusion of the greenhouse gas cost adder.

I agree almost entirely with all of the recommendations from this chapter. I support the recommendation that we need to further examine feed-in tariffs and also support the use of a feed-in tariff for small projects of 20 megawatts or less. I am not sure if the MPR is the right price for these contracts. I think it may be a bit too low, especially for new projects.

I'd suggest as a next step in thinking about feed-in tariffs for larger projects for the CEC, either in conjunction with or prior to the joint CPUC/CEC process, that the IEPR recommends to come up with a white paper or a detailed proposal for how feed-in tariffs might work in the California context.

I think a lot of us who have been thinking about renewables policies and trying to really get a firmer grasp on how feed-in tariffs might work in California versus Europe then we have several questions about sort of the

implications of that approach. And I don't think that the record to date has really provided enough information on the subject so I do think that a detailed proposal or a white paper would be helpful in that regard.

And finally I would like to note that there is some debate over the language of AB 32 as to whether it requires that the greenhouse gas and the RPS markets be separated. And I would just suggest that the IEPR report, that the final report sort of acknowledge that there are dissenting views to it.

And that whether or not the greenhouse gas and RPS markets have to be separate is not necessarily central to the question of how do we properly value renewable resources and how do we make sure that we fully capture the benefits of going to that 33 percent RPS. I appreciate the opportunity to comment, thank you.

PRESIDING MEMBER PFANNENSTIEL: May I just ask, what is your view on separating the RPS from the greenhouse gas market?

MR. CHEN: Our view as an organization is still holding on the subject. I can provide further details in our written comments if that's

okay.

PRESIDING MEMBER PFANNENSTIEL: Yes that would be great, thank you.

MR. CHEN: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Other than that I have the cards from this morning from PG&E and SDG&E. Do you have comments on this subject?

MR. ANDERSON: Rob Anderson from SDG&E. Just two quick points.

First of all I want to make sure I get this right. I think all of us want to see the 33 percent renewables come to reality. When I look at greenhouse gas goals I'm not sure how we get there without achieving that.

But what we don't see in this IEPR is necessarily the fact that says, it is 100 percent feasible. So we just caution folks right now coming to the conclusion that it is 100 percent feasible. This may be a bit of one of those items that is in the hope versus the facts right now and this may be a bit on the hope side. I think -- We hope it gets there and everyone else.

The other reason I'm cautious or hesitant about saying that is it may come off as

saying fine, everything is done that we need to do in order to make it a reality. And I think all of these studies point out that there is going to be massive amounts of transmission and a number of other problems we still need to solve.

And so we'd rather keep those issues out in front of people saying, if we want to get to 33 percent these are the things we need to implement, rather than possibly coming out with a report that says, 33 percent is feasible. Folks will then want to move on to the next topic. So let's keep out in front of them what it is we really need to do to get there.

The second point. We would urge the Commission right now not to take a firm line on should renewables be part of a cap-and-trade system or not. I think there's still a lot of work that needs to get done in that area. What is that cap-and-trade system going to look like. What might it do overall. And we ought to work through the economics of that and not take a hard line position on it at this point in time. Thank you.

ASSOCIATE MEMBER GEESMAN: Rob, I strongly agree with your comments about the

magnitude of work, particularly in the transmission system needing to be done in the renewable area. What significance do you think we should take of the now-increasingly reported fact that some 37,000 megawatts of renewable projects are in the ISO queue?

MR. ANDERSON: I'm not the transmission planner but I know one of the big issues that we're seeing with the queue is that once someone proposes a project and gets in the queue, whether that project is viable or not it remains in the queue. And I think we need a way to get those projects off that were a dream in some developer's mind at one time, he got himself in the queue but it really isn't feasible now, out of that loop because it is taking up space.

We need to do studies assuming everything in front of a given project is going to come to fruition when most everyone knows that that won't happen. So we really need to get the projects that aren't real out of the queue first.

And once again, we've got more renewables in the queue out in Imperial Valley than we've got transmission for. Is it that just more transmission is the final solution? That may

be.

ASSOCIATE MEMBER GEESMAN: It would seem to be a prerequisite, wouldn't it?

MR. ANDERSON: It would be.

ASSOCIATE MEMBER GEESMAN: and then I would think if you built that additional transmission you then have an incentive to at least sort through those renewable projects that were economically viable.

MR. ANDERSON: Right.

ASSOCIATE MEMBER GEESMAN: You'd want to maximize those. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Les.

MR. GULIASI: Thank you. Good afternoon, Les Guliasi with PG&E. The comments that I am about to make basically echo the first comment that Rob Anderson from San Diego Gas and Electric made with respect to the hopefulness about renewables but the cautionary remarks that need to be kept front and center. I guess I'll just express that concern in my own words.

Just a little bit of background. You heard me this morning talk about PG&E's commitment to renewable development with respect to the overall context of efforts to reduce greenhouse

gas emissions. We are currently at about 12 percent with respect to the delivery of renewable energy in our portfolio with retail sales. On a contract basis we expect to be at about 18 percent by the year 2010. The 2007 solicitation process should get us a long way and perhaps even get us beyond the 20 percent contract level by 2010. But we recognize there's a long way to go.

Like San Diego we have concerns about the need for transmission. We are doing everything we can to enable renewable development by exploring the development enhancement of new transmission lines. You're familiar with the effort we have underway in California as well as the effort that we're studying to link California to the Pacific Northwest and beyond into British Columbia. So all of that gives us great hope.

I think the report, this chapter of the report does a good job of balancing the hopefulness and optimism on the one side with the challenges and the barriers on the other side. Certainly the transmission barrier is there. The barrier of integrating intermittent resources into the system. The rate impact is important to us.

And all of that has to be done, if you

put yourselves in our shoes, from the perspective of how we continue to fulfill our basic mission to provide reliable and cost-effective energy to our customers. So again, we are working very hard on this effort. And I want to remain optimistic but it is important just to keep the barriers and the challenges front and center.

Just a concluding remark about feed-in tariffs. Let me back up one step for something I don't want to overlook. As we go through this entire process of AB 32 implementation it is important that we also recognize there's still a lot of work that needs to be done to determine what level of greenhouse gas emissions the electricity sector is going to produce versus how much we're going to get from other sectors.

We're just at the infancy of that work and that analysis and to date it's -- I don't think the studies that we have before us can clearly define or determine how much we expect to get from the electricity sector per se. This is going to be worked out over a period of time and we just have to, you know, watch ourselves and see what we can get from the electricity sector and how much we're going to get from other sectors of

the economy.

Just a concluding remark about feed-in tariffs. We just heard a remark a moment ago about some additional work that needs to be done. A recommendation that additional work could be done by you, perhaps a white paper or something that would provide us with greater guidance and information as we move perhaps to the CPUC to discuss the application of feed-in tariffs.

I think the recommendation that you have here about feed-in tariffs for small generators is a good start. I'm not sure if 20 megawatts is the right number but we'd certainly support the notion of developing feed-in tariffs for small generators.

I think the jury is still out with respect to the need for feed-in tariffs for large generators. It is not clear to me that absence of a feed-in tariff is the biggest obstacle. I think that the obstacles that we've identified such as lack of transmission may be more the reason for lack of progress for the large generators.

But I think we need to do some more work before we can say definitively what the megawatt level cutoff might be and for which groups we do

need a feed-in tariff. Thank you very much.

CPUC COMMISSIONER BOHN: Before you sit down may I ask a question? Do you think the report adequately describes the severity of the limitations of getting to this 2010, these 2010 goals?

There's a certain amount of skepticism in the halls about whether or not this is going to happen, whether or not the report itself in an interest of being hopeful and being sort of what is currently fashionable does not adequately address the seriousness and the immediacy of the concerns in terms of getting there. Are you okay with the report as a representation of the obstacles to get there? Do they get it right, do they express them forcefully enough in your opinion?

MR. GULIASI: Well I think overall the report is more optimistic than we would be about the feasibility of achieving greenhouse gas reductions or achieving a percentage of renewables in our portfolio.

I think the report does a good job of identifying the challenges and the barriers. I think that on balance there's greater hopefulness

and optimism placed on the achievement of worthy goals, you know, at the expense of, you know, fully understanding the challenges and recommending actions to overcome those barriers and those challenges.

ASSOCIATE MEMBER GEESMAN: Les, I want to go into the feed-in tariff a bit with you because I think it is something of a double-edged sword. You may be paying too much for certain renewable projects and not enough for others. And it would seem to me that one of the attributes of the tariff system that several of the European countries have adopted is differentiated by technology types. And I wonder if that is something that would be in the best interest of your customers. To make it as blunt I guess as possible, should you be paying as much for wind-generated electricity as you would for central station solar?

MR. GULIASI: This is exactly the kind of question I think needs further analysis. You're right. What you referred to in the past as the Goldilocks paradox or the Goldilocks problem. What is the right amount to pay? What we don't want to do is lock ourselves into a situation that

we have experienced before with long-term, standard offer price contracts that don't reflect market conditions.

And perhaps it is a question of differentiation by size, but more appropriately, differentiation by technology. And maybe we do need to pay more for certain technologies and less for others and accurately incorporate and recognize all of the costs associated as we're, you know, getting to understand through the intermittency analysis on the cost of integrating intermittent resources into the system.

So I don't think there is a one size fits all or a blanket approach. It may be that we need to do a greater, a better job of differentiating size technology and so forth.

ASSOCIATE MEMBER GEESMAN: Now let's say that everybody has gotten on the bandwagon of building more transmission, the regulators, the utility companies. Everybody thinks we need to invest quite a bit more in new transmission. And we prebilled a couple of billion dollars worth of transmission out to some remote resource area. And there are five or six prospective solar plants, there are two or three thousand megawatts

of prospective wind farms in this remote area that the rate payers have just expended a couple of billion dollars on.

How do we determine what you should pay for generation from each of those five or six solar projects? Is that one where the current bidding process or solicitation process is properly designed or is that one where a more logical, and frankly a more economic approach might be a regulated price?

MR. GULIASI: You're talking about a price just for the generation, the product that is generated, the electricity generated. Well, is this a chicken and the egg problem where we have what do we develop first, the transmission or the generation?

ASSOCIATE MEMBER GEESMAN: I can point to a couple of places on the map where we are building a couple of billion dollars worth of transmission, or at least planning to.

MR. GULIASI: That's right. And I think you talked about what if we all get on the bandwagon. I think we are on that bandwagon. And I think as a state we have made a massive commitment to build transmission, not knowing for

sure how much of the potential will be realized. We know we have what, 4,500 megawatts of potential in the Tehachapis and we're all hopeful. I don't think the transcript can get the hand signal here with my fingers crossed. But we're all hopeful that generation will materialize if the transmission is there.

And we're looking at the feasibility, as you know, about building an extensive transmission line along with other parties into the northwest and beyond because we're hopeful based on studies that we have undertaken and others have undertaken to look for the potential.

I think this really is a chicken and an egg problem and it is hard to answer the question without kind of just stepping back and saying, maybe you ought to socialize those costs, the costs of transmission, and hope that the generation is there to make use of the transmission.

ASSOCIATE MEMBER GEESMAN: Well it would appear in a couple of the examples we have already crossed that threshold and decided to socialize the pre-build of the transmission. My question is not whether that's a good idea or not. I happen

to think that it is.

My question to you is, what happens when we get to the end of the line and we are now in the renewable development zone. Do we have an option? Take people on a first-come first-served or on a best fit basis or do we establish a price that we're willing to pay for generation from that particular area? Which fits your interests best, which fits your customers' interests best?

MR. GULIASI: I'm not sure I know the answer to your question.

ASSOCIATE MEMBER GEESMAN: I think those are questions the two commissions are going to have to wrestle with next year in determining whether this feed-in idea is a good one or not.

MR. GULIASI: And you have a FERC overlay that needs to be taken into account when you have that, that discussion.

ASSOCIATE MEMBER GEESMAN: Yes. Thanks very much.

MR. GULIASI: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thanks Les. We have somebody on the phone who would like to speak to this subject. Joseph Langenberg from Central California Power.

MR. LANGENBERG: Yes ma'am, good afternoon.

PRESIDING MEMBER PFANNENSTIEL: Good afternoon.

MR. LANGENBERG: I'd like to make a couple of points, some that were alluded to. I recall reading the transcript of Commissioner Geesman's workshop back in the end of May where we were comparing the progress made from European renewable programs with California.

And one of the things that struck me was that everyone in Europe recognizes that it costs more for renewable power so they were willing to pay more money for renewable. And secondly it appeared that the regulatory people were cooperating with the people trying to develop the renewable power. Which here in California you have a whole lot more of a problem with the regulatory system. That's one of the things.

Secondly, with the idea of costs. I'm sure that the Commission has heard Mr. Reese, Mr. Phil Reese of the Biomass Alliance, bemoaning the fact that the biomass industry has been, you know, it has a problem. It has one heck of a problem trying to make money at the rates that

they are being given.

This latest discussion talking about the rates for different technologies, I have another question to pose. What is the price differential or what should the price differential be if someone could provide reliable renewables? By reliable I mean dispatchable. It is there when you need it, yo can dispatch it, you can run it and it is not an as-generated.

Is reliable energy worth more than as-generated? I mean, I won't answer the question because obviously I'm biased. But this is a point that has to be brought up. Because ultimately the way to get something moving is if it costs it must be paid for. There ain't no free lunches. No matter of how we try to rationalize it, renewable energy costs more than conventional fuel energy. I mean, that has pretty been established. We must recognize that it is going to cost and if we want it we have to pay for it. That's just about all I have to say and thank you for letting me speak.

PRESIDING MEMBER PFANNENSTIEL: Thank you, sir. Any other comments on Chapter 4? Yes, come up, Paul.

MR. VERCRUYSSEN: Good afternoon,

Commissioners, Paul Vercruyssen from the Center for Energy Efficiency and Renewable Technologies. Thank you for the opportunity to speak here today. We'll be filing more formal written comments. And I apologize I don't have anything formally prepared for today but I did just want to make a couple of comments on this chapter.

I think the general agreement in the room is that there is quite a lot to be done to achieve the various renewable generation targets that we've set out for ourself in California. I would just say that from the perspective of my organization that is directly tied to reaching our climate goals.

And I would in many ways agree with comments from the gentleman from SDG&E that keeping the focus on the 33 percent goal is very much important. There's a lot of things that we need to do to get there. One of the very first things that CEERT did once AB 32 was passed was come at it from the perspective of how do we reach those goals working back from success. And we found that achieving the climate targets for the state of California if you break out the electricity sector, you need about 33 percent

renewables targets.

So rather than envisioning all of the hurdles that we need to do I think one of the other ways you can look at this is that this chapter and the IEPR in general does a very good job of outlining what needs to be done to reach these goals. And we should be focusing on the 33 percent goal even more than the 2010 20 percent goal.

We need to focus on how do we get these transmission projects built. A lot of the different obstacles that you've talked about in the transmission queue, permitting pricing issues, are all very important and we'd like to keep the Commission, both Commissions focused on those goals.

In regards to the question of pricing specifically. I think that this IEPR does a very good job of beginning to talk about not just the cost of renewables but the values. The greenhouse gas adder. And attempts, difficult as they may be, to try and assess the fuel price risk for fossil is an incredibly important thing for the Commission, both Commissions, to attempt to do. Because it is a value of renewables that you don't

have that fuel price risk and it is not accounted for.

That said I think it is also important to differentiate between what the MPR price actually is. That it is a market price benchmark. And that the other assessments, the greenhouse gas adder or the fuel price risk, you actually begin to talk about the value of renewables. And that is an important distinction that I think can't be made clearly enough.

That's really all I have to say right now. But we'll have, as I said, more extensive comments and I appreciate the time to talk with you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, we look forward to your comments. Anyone else on Chapter 4? Then we move on to Chapter 5.

MS. WHITE: Linda Kelly is going to begin the discussion on the chapter related to the distribution system. She will be joined by John Sugar to complete the rest of the presentation.

MS. KELLY: Good morning. Good morning? Good afternoon. I am going to give you an overview of Chapter 5 on distribution systems. And then as Lorraine said John Sugar will conclude

with the distributed energy resources and the recommendations in that particular section.

We are going to cover existing distribution infrastructure, California infrastructure challenges, distribution system investments, the research program on distribution and then John will do the integrated distributed generation resources.

The utility service territories in California are really very varied. And when we look at the distribution system it isn't easy to take any one distribution system and say problems or solutions fit all of these distribution systems. They are very varied in geography, size, urban. Some utilities have a lot of urban customers, others have a mix of urban and large rural customers. So the problems for each of these utilities in serving these customers with their distribution systems is really very varied and the challenges are very unique to each of their service territories.

These systems though, one thing they have in common is they are designed to accommodate one way power from central station power plants to customers. Also the distributed generation that

we'll talk about at the end of this presentation is viewed by all utilities as negative load and is invisible to their operators.

These systems are aging rapidly and they need to be replaced to assure that reliability problems will not increase in the next decade.

One other important fact is that 90 percent of customer outages occur at the distribution level. And although most people know that when trees hit power lines there's problems a lot of these problems are caused by underground cable failures, underground equipment failures and also whether -- and other occurrences.

But it is really important to note, and although today I am focusing mainly on the investor-owned utilities because they were the people that came to the workshop and shared a lot of this information. In review of a recent presentation by the Los Angeles Department of Water and Power to their board, when they talk about outages and percentage of outages they also are experiencing, the largest percentage of outages has to do with underground cable failures. And they are also accelerating their attention to underground cable as well. So this isn't just

IOUs it is all utilities.

Now that I mention the underground cable. When we talk about infrastructure challenges for distribution in California and probably all over the United States I think these problems are not unique to California. One of the first infrastructure challenges, and this is one that the investor-owned utilities came and said is their top priority, is aging underground cable.

People like underground cable. And I think that if you have a new home development being built in the near future it is not going to have overhead, it is going to have underground. And approximately 75,000 miles of underground cable are installed under the streets of California, in the backyards, under swimming pools, they're everywhere. And a significant percentage of this cable is approaching the ends of its useful life.

When the utilities came and talked about this at the Committee workshop that we had, this problem is really significant. Because of the 75,000 miles of underground cable there is a very large percentage of it that is certainly beyond its existing life and is going to be failing in

the next 10 to 15 years and maybe even sooner than that.

As an example, PG&E -- and PG&E wasn't the only one, they just gave us a clear example that we were able to really focus on and get an idea of what the magnitude of this problem is. They said that they have 26,000 miles of underground cable, they are currently replacing it at 70 miles per year, and Commissioner Geesman calculated that this is equivalent to a 371 year replacement cycle.

ASSOCIATE MEMBER GEESMAN: What's the matter with that? (Laughter.)

MS. KELLY: Replacement costs for one foot of the cable is $120. So this is a really significant problem. And when we talk about a lot of the issues that California faces I think it is really important that reliability is critical to everything we do. And although this isn't something that has gotten a lot of focus from people it is an infrastructure challenge in the distribution area that we all have to be aware of.

Also with regard to distribution. There's been very little focus on distribution. Over the last couple of years smart grid

technologies have become something that everybody is talking about. I think currently now utilities are in the process of rebuilding their systems and they are rebuilding them just as they did them 30 years ago.

There isn't a lot of innovation and incentives for innovation to try to utilize some of the existing smart grid technologies that are currently there and certainly not a lot of encouragement to look at the advanced distribution technologies that are on the horizon and are still in the research stage and see if they can utilize those to change the design of the distribution system.

Aging workforce. This is a big issue for everybody I think in a lot of sectors, including this commission. But the aging workforce was something that was raised as an issue for keeping good engineers to design the system of the future. And then from an operational point of view we're talking about replacing underground cables. You're going to need a huge workforce to do that work. And that workforce is also declining and it is hard to attract people to get into that industry as well.

And then I think the last challenge is lack of understanding and agreement about what the distribution system of the future is going to look like. We know the distribution system is changing because we're putting distributed generations all over that system. How it changes in the future and how it will serve customers and utilities is something we really haven't stopped to take a chance to look at and evaluate. What do we want to do, how do we want to get there. So that to me is another one of the challenges.

Investments. I mentioned that the distribution system is aging. And along with that aging distribution utilities all over the state are investing in upgrading their distribution systems. The numbers change from year to year and we have rate cases and some years there's some investments in transmission and other years there isn't. But in general about two-thirds of the capital budget that the utilities ask for each year is spent on upgrades and new infrastructure in the distribution area.

And clearly at the workshop that we had Edison and other utilities said that billions of dollars are going to be invested in the next five

to ten years to upgrade these systems. So we're really at a junction now. They're upgrading these systems, they're going to be putting in new equipment. And the big question is, what will that equipment look like, what will those designs look like and will they still serve California in the next 10 to 20 or 30 years? Because these are long-term investments.

So it is important that we all agree that business-as-usual, the distribution systems that served us well in the last 20 or 30 years are now obsolete and are -- not obsolete but they need to be transitioned. So as the new digital economies are developed here in the state that we can, that the distribution system can accommodate all the needs of the customers and this new digital economy in California.

To assure maximum reliability and leverage these benefits from these new distributed energy resources this system is going to have to accommodate two-way power flow. Business-as-usual isn't going to work anymore.

And one of the key ways that we are going to get there is through using smart grid technologies. I think this new design will have

to be smart, and again, it will have to support two-way power flow.

I just wanted to just quickly just mention these modern/smart grids because I think it is really important. There has been a lot of discussion about modern/smart grids. Government agencies, DOE, the federal government, has taken on the challenge that the grids going from transmission right through to distribution are old and need to be modernized. This is a national issue, not just a California issue. So there's been multiple efforts over the last three to four years to modernize the grid.

In general what it means is self-healing. They want to move from transmission to distribution where faults can be assessed, diagnosed and they can be repaired with very little interface from humans. An example of how that has already happened, if you go to some of the refineries. There used to be lots of people in refineries but now much of that operation has been automated and a lot of that is done without any human interference.

The reason I wanted to highlight this. In California the San Diego School of Law

partnered with San Diego, the Utility Consumer's Action Network, UCAN, and did a smart grid study. So California took a step forward instead of talking about it. And there's been a lot of talk about it. They actually went ahead and they looked at the regional -- San Diego from a regional perspective and said, can we do this, does it make sense, where is it cost-effective.

I think it is really important to highlight that because now San Diego and those agencies down there have made a commitment to start looking at and implementing some of these smart grid technologies. They have applied to DOE for a large grant and we are working closely with them to see, you know, can we get these smart grid technologies. The ones that are available get them in the system, get them demonstrated, and can we begin to look at what we'll need for the future.

And again, smart grid technologies. This is really important that everybody understand is that they aren't just one size fits all. And it is important that this movement towards smart grid technologies really focus on what is cost-effective. I think that each system has to be

evaluated and it has to be forward compatible and backward compatible. And mainly again I think the key to all this is to make it cost effective.

The distribution research program. I think all industries need research. And the Public Interest Distribution Research Program is focusing on developing a portfolio that supports the reductions in greenhouse gasses, improved distribution reliability and capability, and also looks at supporting the optimized utilization and integration of renewable resources. Demand response, energy storage by utilities and customers.

We are working with an underground cable diagnostics. This is really key. I think that the National Science Foundation now has recognized this is important. And research that we just recently started, which is working with professors from multi-disciplinary areas in Berkeley, resiliency of the infrastructure is now a focus of the National Science Foundation. So we will be partnering with them and trying to bring our work and combine it with theirs to see if we can really try to resolve this very important reliability issue that I think faces all utilities, not only

in California.

Smart grid technologies will be looking at distribution automation research, microgrid research, communications and standards, to assure that all these systems can speak to each other. And again, they will be forward-compatible.

Distribution models and planning. Key to a lot of the things that Commissioner Geesman and others here in this room want to support is understanding where renewables, smart grid technologies, distributed generation make sense. Where they are cost-effective. So having power flow models like they have at the transmission level at the distribution level, will help utilities and regulators understand what the choice are and what the costs are.

Sensors. This seems very simple, but if you are going to monitor a huge distribution system you are going to have to have ubiquitous, cheap sensors that can cover miles and miles of area so that the system and the condition of the system can be relayed to everybody quickly.

Recommendations. I'm just going to summarize the recommendations in the IEPR that I think are consistent with the issues that we found

and the problems that I think that we've identified.

Develop state policy that will articulate and support modernizing California's distribution system. The federal government is looking at it. I think it is important that the state look at it as well. They are clearly looking at what they should ask the states to do. But I think now is the time, as we invest in all this distribution, is figure out what we want, what we need, and work with both the utilities and customers to get a common agreement on that.

Establish transparent distribution planning processes to assure timely investments in innovative technologies. Again, if you can't see it you can't understand its value. You have to be able to see what the distribution system needs, what the alternatives are and what the cost tradeoffs are.

Establish a program at the Energy Commission to assess distribution system adequacy and modernization. We currently have a transmission program that looks at that. I think we need a neutral place to begin to look at, you know, what these changes are and how those changes

should be employed and what technologies should be used.

Fund public interest distribution research. The program that we are currently funding I think is making good progress. We're collaborating with the Department of Energy and other research agencies, both science and government, and working on solving some of the technical issues that are critical to the resolution of some of the policy issues.

Support system inter-operability. All this stuff has to talk back and forth to each other or else we are going to have a lot of systems that will have to be replaced with whole new systems.

Develop new rate designs that will encourage investment in and participation in programs that have value to the state. At the joint workshop that we had customers came and talked about programs that will incent them to participate in some of the programs that the state would encourage.

As an example, customers are now going to have PV, they're going to have demand response. These are resources that they can use for their

own use or they can use to potentially sell in a market. Customers would want to have programs that would incent them to do that, incent them to invest in PV on their own, incent them to participate in demand response programs. So it is important that the rate designs will encourage investments in these programs.

Broaden incentives to utilities beyond investing in infrastructure that supports a high volume of electricity sales. I think that is self-evident. utilities really don't have right now a lot of incentive to do things that improve operational efficiency. States and other countries are exploring how you can operate the distribution system more efficiently using new technologies that have never been available before. So I think that it is important that we look at those type of technologies and see, can you incent the utilities to operate their system more efficiently if they have the technologies that will assist them to do that.

Recovering remaining book-value costs of obsolete equipment when smart grid technology provides substantial incremental benefits. We believe that there is going to be some real

changes in how the distribution system operates in the future. Investments can't stop while we wait for those changes. But it is important as those investments go into the future that when there is new technology that will really provide value to rate payers in California that utilities be allowed to invest in those technologies and move forward. John.

MR. SUGAR: Thank you.

Since the late 1990s the Commission has presented the case for expanding use of distributed generation in California. Distributed generation provides efficient use of fuel, it can improve local reliability and it can provide reduced stress and congestion on the state's transmission system.

But significant issues are still slowing development, even after this time. Rate design issues have been a particular problem in creating uncertainty for the industry.

Issues surround the charges and fees that distributed generation developers face. And the timing of legislative mandates regarding tariff design and program design have been affecting the viability of distributed generation

in California.

If we are going to successfully expand the use of distributed generation we need policy direction focused on the long-term growth of this resource in the state.

The 2005 Integrated Energy Policy Report identified a number of key issues in expanding the use of distributed generation. A couple of the largest were, first, the Self-Generation Incentive program should include larger, natural gas-fired projects. As a result of economies of scale these large projects are the ones that provide the greatest efficiency in the use of -- thank you -- the greatest efficiency in the use of fuel. They also offer the bulk of capacity that's available for combined heat and power systems in our state.

The second issue was access to the grid for combined heat and power systems. This was the most important issue for the larger systems. That access alone could add 2500 megawatts of capacity for export within our state by the year 2020.

From comments that the IEPR process has brought out, municipal utilities appear to be welcoming distributed generation development.

They include combined heat and power projects in their planning and seem to be relatively, have a relatively conducive environment to the development of combined heat and power and other distributed generation.

The investor-owned utilities appear to show little interest in accepting energy from generation at customer-owned sites. At the same time the utilities appear to have little interest in owning non-renewable distributed generation projects themselves.

The developers of distributed generation projects with whom we have been involved state that this has continued to create difficulties in trying to site projects in the investor-owned utility service territories.

Much of the existing large cogeneration capacity on which we are currently relying is still running under contracts from the 1980s. These are going to be expiring in the near future. This could seriously reduce the amount of available capacity in California and we could lose up to 2,000 megawatts of fuel-efficient generating capacity by 2010.

Replacing it by remote-generating

resources will increase transmission and distribution losses, will increase instances of congestion and can reduce local reliability.

There have been a number of new developments in the state that appear to benefit distributed generation. The first is that the fuel efficiency of distributed generation, particularly combined heat and power, can help us reduce the greenhouse gas emissions from our electricity generating system, helping the state to meet the aggressive goals of AB 32.

The second area is that distributed generation can now serve to meet local capacity requirements. As the Independent System Operator is reducing its reliance on reserve and must run capacity it is encouraging California's utilities to provide capacity for reliability in load centers. And distributed generation and load service in load centers can help to provide this service.

The 2007 draft IEPR includes a number of recommendations to encourage greater development of distributed generation. These include basing the Public Utilities Commission's Self-Generation Program's incentives on efficiency and system

performance rather than fuel type.

The CPUC's tariff structure could make DG projects cost and revenue neutral, granting the owners credit for system benefits that their projects can provide.

The PUC and CEC should partner to eliminate non-bypassable and standby reservation charges for distributed generation.

And the CPUC should continue the work of the Rule 21 collaborative on interconnection standards. That work began as a collaboration of the Energy Commission and Public Utilities Commission and has been valuable in reducing some of the roadblocks to integrating distributed generation in California's system.

The CPUC should develop a DG portfolio standard for utility procurement plans or treat distributed generation like efficiency programs.

And the CPUC should adopt revenue neutral programs with high efficiency CHP on an equal footing with bulk power from utilities. This could include the utilities procuring natural gas for combined heat and power to share power plant rates, counting combined heat and power output toward utility energy efficiency goals and

providing a portfolio standard with steadily increasing requirements for combined heat and power generation.

PRESIDING MEMBER PFANNENSTIEL: Thank you John. Questions? Yes Commissioner Bohn.

CPUC COMMISSIONER BOHN: You've commented on one of the reasons that this whole thing is not doing any better is, I think you called it the reluctance of the investor-owned utilities. Can you elaborate on that. Who is saying what? Is this a length of procurement contract issue? Is this a, I just don't want to deal with those guys issue? What is the issue?

MR. SUGAR: From comments that have been made in this proceeding there is a difference in perception between the developers of distributed generation projects and the utilities. Southern California Edison in particular seems to be very concerned that distributed generation projects do not reflect an efficient use of fuel efficient generating options. The utilities seem to be concerned about reliability of their systems.

CPUC COMMISSIONER BOHN: Reliability of the utility system or the generation system?

MR. SUGAR: Of the utility systems.

That the distributed generation systems could impinge on that rather than serve to bolster system reliability.

They do seem to be concerned about having to pay above market rates for power. The concerns regarding opening the grid to the larger combined heat and power projects haven't been as specific in some of the comments we've gotten on efficiency of the systems but seemed to relate to the ability of the utilities' distribution and transmission system to deal with the power flows.

PRESIDING MEMBER PFANNENSTIEL: Other questions from the dais? Thank you John.

We have several blue cards from people who are on the telephone. Do we have other people in the room here who want to speak specifically to this chapter? Otherwise we'll go to the phones. We'll start with Eric Wong from Cummins Power Generation.

MR. WONG: Yes. Can you hear me okay?

PRESIDING MEMBER PFANNENSTIEL: Yes, just fine.

MR. WONG: Very good, thanks. Good afternoon Commissioners of the Energy Commission and the Public Utilities Commission. I do have

some comments but first I would like to ask a question of John Sugar, which is on slide number 12, which is the slide on integrating distributed generation. Under the second bullet, the first indent, Self-Generation Incentive Program should include larger, natural gas-fired projects. And my question for John is, does he have a size in mind when he says, larger?

MR. SUGAR: No. Currently larger would probably be larger than 20 megawatts, which is the size the current legislation has been calling out.

MR. WONG: And the current legislation, you're referring to AB 1613?

MR. SUGAR: Yes, AB 1613. And I believe also the road map, the policy planning road map which we presented at the IEPR workshop also was focused on systems that were below 20 megawatts. In the 2005 IEPR I believe the Committee was focused on systems that were larger than that.

MR. WONG: Okay. My first comment, and thank you John, is that one of the -- I do want to compliment the staff on the comprehensiveness and the thorough treatment and the very high quality of this report.

My first comment as a follow-up on that

discussion with John Sugar is that this section dealing with distributed generation in Chapter 5 could probably use a paragraph that distinguishes between the under megawatt on-site power or the CHP that is serving a customer's needs versus what the IEPR says the larger cogenerators that could use (indiscernible).

The business technology model or on-site CHP systems that are built to meet the needs of the customer are different from the larger co-generators. This is more of a factual distinction because many if not all of the recommendations that are made at the end of the presentation today as well as in the report we would also support. And I believe that the larger co-generators would also support it, we have a lot of commonality in that. But the report could benefit greatly by such a distinction and we will be putting that in our comments to you this Friday.

And I do also want to say that I am representing, I'm speaking on behalf of the California Clean Distributed Generation as well.

The last set of comments, and like I said before, we do support the recommendations on distributed generation, the six recommendations

that John finished up with. And I do want to comment in particular on item number six that's talking about revenue neutral programs.

And the first indent says that utilities procure natural gas for CHP at power plant rates. We would recommend, and again this will be in writing, that this be made an option available to CHPs. In this case we're talking about the owners of CHP units on-site that are conserving their load. And I think this is cached by the phrase revenue neutral programs. But if I were to clarify that, at least in our thinking, that's a program set up to for procuring natural gas. We believe (indiscernible).

The last comment is on the second point there, the counting the CHP output toward utility energy efficiency goals. The Coalition, the Clean DG Coalition has supported this through the evolution of the IEPR when it first developed its policy pronouncements on distributed generation and combined heat and power.

We hope this can be accomplished and specifically stated more strongly in the Joint Energy Action of the CEC and CPUC. If not then I would like to revise a proposal, I think that was

done in the 2005 IEPR, which was the CHP portfolio standard. And I think that is something that cannot be considered (indiscernible) has to be considered as an energy efficiency goal. And we would strongly advocate that the CHP portfolio standard should be revisited. That concludes my comments.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much. Rosemary McMichael from Current Group LLC. I'm not sure I'm reading that right.

MS. McMICHAEL: It's Rosemary McMichael. Thank you, good afternoon.

PRESIDING MEMBER PFANNENSTIEL: Good afternoon.

MS. McMICHAEL: I'm the director of regulatory affairs at Current Group and we are a smart grid company based in Maryland. Right now we are deploying a smart grid network using broadband over power lines with the utility known as Oncor, formerly known as TXU. Right now we have equipped over 100,000 homes and by 2010 we will be in two million.

So I just wanted to applaud the staff for the direction of the report and of course in particular the discussion of smart grid technology

as an upgrade to the distribution network. We are doing this today in Dallas. We have different assets of our distribution management suite which includes sensors and outage detection and restoration of voltage monitoring.

In particular I wanted to support your recommendation that they accelerate the transformation of the distribution grid into an intelligent and sustainable network. And to encourage you, given our experiences, to encourage rate designs that will encourage the utilities to invest in a smart grid upgrade. And also consumers to adopt the demand side management products to implement customer energy management controls.

The only question I had applied to your really thorough and very good report. It seems that the sensor product is seen as a stand-alone. We would encourage you to view that, the sensors throughout the distribution network, as simply a piece of a holistic solution. But you can achieve some better cost figures if it's just one piece of a system that is deployed. The evidence for us is in Dallas. There's only one -- a number of (indiscernible) that we provide. And that

concludes my comments.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much. San Diego Gas and Electric, Rob, if you have further comments on this or Les from PG&E. Anybody else here or on the phone with comments on Chapter 5?

MS. SHERIFF: I have comments.

PRESIDING MEMBER PFANNENSTIEL: I'm sorry, I have your card here too. Please go ahead. Nora, go ahead.

MS. SHERIFF: On behalf of the Cogeneration Association of California and the Energy Producers and Users Coalition first I would like to thank the IEPR Committee and the Energy Commission staff for continued strong support for CHP and cogeneration resources. It is at least in part due to the Energy Commission's support, as pointed out in our statement, that the Public Utilities Commission is now implementing a new prospective QF program. And that QF program should serve to retain the existing line of CHP resources for the state of California.

We do ask for your continued support during the implementation of the QF program and will file written comments on Friday. But I would

like to make a few specific comments on the Draft 2007 IEPR here.

First, the 2007 Draft is clearer than past supports have been on the Energy Commission's position that large CHP facilities, and by large I mean facilities greater than 20 megawatts, are included as DG or on an equal footing with DG resources, regardless of size.

But the draft could benefit from greater specificity in some areas. For example, on page 194 the draft recommends elimination of NBPs for DG. And it must be crystal clear that these non-bypassable charges should be eliminated for all CHP facilities. The unquantified, non-bypassable charges related to utility procurement show up as development of new CHP facilities and new DG facilities.

And I would like to ask for specific Energy Commission support for an exemption from these charges for combined heat and power and DG in the 2006 long-term procurement proceeding ongoing at the Public Utilities Commission.

Second, regarding the natural gas procurement recommendation also on page 194. The CAC and UPUC could support this approach under two

conditions. First, as Mr. Wong noted, the program should not be mandatory. It should be voluntary for the CHP facilities, recognizing that large CHP facilities may (indiscernible) natural gas. And second, this program should not lead to any additional non-bypassable charges.

Third, the draft also recommends allowing large CHP projects to find customers that are excess generation and to export power at wholesale prices. While this sounds like a good idea it is a difficult thing to do, find customers in a market where there are really only a few wholesale purchasers, PG&E, SCE and SDG&E.

Finally, we will propose a recommendation that ties in to the technical discussion on combined heat and power, specifically adding as a recommendation measures and regulations that fully reflect the benefits of CHP when compared with separate productions of thermal and electric energy.

Again, thank you very much for your continued support for CHP and we will file written comments on Friday. And thank you for this opportunity to speak.

PRESIDING MEMBER PFANNENSTIEL: Thank

you. Thank you for your comments and we look forward to your Friday comments.

Now I do know that Southern California Edison would like to offer comments on the, I believe the entire scope of the report.

MS. WHITE: Ms. Jones is here to make those comments.

PRESIDING MEMBER PFANNENSTIEL: Okay, fine, thank you.

MS. JONES: Good afternoon. It is the end of the day. At Southern California Edison we thought that the IEPR, being a single report we decided to consolidate our comments as opposed to doing it chapter by chapter. But I appreciate the opportunity to be able to speak to the Commissioners today. I also want to congratulate the staff on all the hard work that they have done putting this document together.

Edison is fully committed to any state policies concerning GHG reductions. As you know we are the leader in renewable procurement, the leader in energy efficiency savings, and also I have a press release here that I would like to provide to the Commissioners about our new Avanti circuit, which is our circuit of the future.

ASSOCIATE MEMBER GEESMAN: A story in the Los Angeles Times today did a very good job of describing that and it has been a project that we followed with great interest for quite some time.

MS. JONES: Thank you. We want to support the CEC in their efforts to implement the policies that are described in the 2007 IEPR and we intend to provide substantial comments on Friday. But I wanted to provide an overview of some of the areas that we're going to cover just to show what we plan to talk about.

Our areas, our general areas of concern are planning and conventional generation, specifically the portfolio analysis and common planning assumptions, nuclear generation and natural gas.

Loading order resources, energy efficiency and renewable resources.

And distribution, distribution investments and distributed generation.

I want to go through these fairly quickly, especially since it's the end of the day. And like I say, we'll provide significant comments on Friday.

The IEPR recommended use of a

standardized portfolio analysis approach for long-term procurement planning. Edison would like to maintain flexibility in the methods that we use to provide long-term procurement plans. We believe that the standard approaches aren't appropriate for each IOU has very different portfolio mixes, very different profiles, and those things need to be taken into account to be able to get the lowest cost, best procurement plan that you can get.

ASSOCIATE MEMBER GEESMAN: Let me try and be as clear as I possibly can that it is a product of several years of growing dissatisfaction with the methodologies which you have used in your procurement process that prompts us to make a recommendation for greater standardization.

The other two investor-owned utilities seem to have moved forward with greater diligence in replacing their reliance on older steam turbines. They seem to have demonstrated a little bit greater sensitivity to the impact of fuel cost pass-throughs on their customers and their desire to improve the efficiency with which natural gas is burned for the generation of electricity, and they haven't quite gotten their customers into the

reliability pickle that seems to present the state in your service territory every summer.

So while you may have preferences as to your own, I would say quite opaque methods of performing procurement analysis, you need to understand that that's been met with growing dissatisfaction on our part over the years.

MS. JONES: Well we would like to work more collaboratively with the CEC with respect to different issues, especially this one, regarding methods that we have the ability to use for future procurement planning. You know, we're open to working collaboratively.

ASSOCIATE MEMBER GEESMAN: I'm sure my colleagues would welcome that.

MS. JONES: I'll move on to nuclear energy. Which from Edison's point of view, because we are trying to reduce, implement AB 32 and reduce our GHG emissions, we believe that nuclear energy should be included as a long-term generation option, especially using the portfolio analysis. Well not specifically these tools but in doing portfolio analysis as the IEPR suggests over a longer period of time. We believe that it should not be thrown out as an option this early

in the, this early in looking at the future.

ASSOCIATE MEMBER GEESMAN: Again I don't think anybody has thrown it out as an option. State law does create certain requirements that need to be met before another project can be sited in California. But I don't think that anyone at the Commission has dismissed it as an option. And I'm curious whether your company does intend to take any early actions to facilitate its use such as early site permits.

MS. JONES: Yes, we do.

ASSOCIATE MEMBER GEESMAN: When and where?

MS. JONES: I'm sorry, I don't know the specifics but I do know that it is part of the plan.

ASSOCIATE MEMBER GEESMAN: I look forward to hearing more about that.

MS. JONES: Once-through cooling, the aging power plant retirements. We support the ISO study that is currently ongoing. I believe the key stakeholders are all the other utilities as well as the CEC and the ISO. And, you know, we look forward to the actionable plan that will result from that study.

With respect to natural gas. The current CEC forecast has gas prices going up significantly in the later years, especially after 2015. Edison and its vendors' experts don't really agree with that view and we would support the CEC in their continued verification of their models to reevaluate that conclusion. It doesn't appear to be a market consensus conclusion.

CPUC COMMISSIONER BOHN: Just out of curiosity. I'd love to hear your guys talk about that. Sometime when they're wandering around the PUC would you ask them to stop by. I'd love to hear the rationale behind that position.

MS. JONES: Okay, I'll mention that when I go back to the office.

With respect to energy efficiency and the adoption of statewide targets for energy efficiency for 2016 equal to 100 percent of cost effective efficiency.

In the statewide EE Potential Study done by Itron they used several scenarios which incorporate more real life program limitations such that the market full potential, which is providing 100 percent incentives to customers, results in about 45 percent of the economic

potential. We believe that should be the maximum target because scenario results were used to develop the estimates.

ASSOCIATE MEMBER GEESMAN: Do you see a problem with only shooting for 45 percent?

MS. JONES: Well, economic potential is theoretical. Earlier there was a gentleman here, I believe he was a contractor speaking about his wife who doesn't like the color of fluorescent bulbs. If we gave them to her for free she still wouldn't use them. That's kind of real-life, programmatic issues that are dealt with every day. You can't give it to 100 percent of the people because they just don't want it.

ASSOCIATE MEMBER GEESMAN: And the only way in which to achieve that potential is giving stuff away?

MS. JONES: We hope not. We'd like to do it in a cost-effective manner.

ASSOCIATE MEMBER GEESMAN: But allowing for a 55 percent slop factor seems to be a pretty low standard, isn't it?

MS. JONES: Well again, it's what the scenario results of the statewide study produced.

PRESIDING MEMBER PFANNENSTIEL: But

excuse me, wasn't that based largely on current programs or current program configurations? I think one thing we didn't hear this morning in this discussion was that we're not going to make 100 percent with the existing programs. That what we need to do is look at what programs will get us to 100 percent.

MS. JONES: Right. Edison fully agrees with that. One of the things in the IEPR report that we were really glad to see was that they were taking into account standards and other ways to incent efficiency applications.

PRESIDING MEMBER PFANNENSTIEL: But with all of that you still think 45 percent should be the goal?

MS. JONES: Based on the statewide potential study, yes.

We also support the investigation of white tags for use as a market based approach for energy efficiency.

Renewable resources. We believe that the analysis done in the IEPR report isn't enough of a basis for the conclusion that 33 percent is feasible. We believe that there needs to be further areas of study, especially in the areas of

reliability and operability of the system under those conditions.

We do definitely agree that there need to be changes in the transmission planning system.

For feed-in tariffs. As you are aware we support the use of feed-in tariffs for small projects up to one and a half megawatts but we don't support feed-in tariffs for projects greater than 20 megawatts.

ASSOCIATE MEMBER GEESMAN: Let me ask you. Your ratepayers prebill $2 billion worth of transmission out to a particular renewable resource area. How do you determine what you're going to pay for generation from that area?

MS. JONES: Well we believe that you can determine the value of the renewable resources through analysis that's done in the RPS process.

ASSOCIATE MEMBER GEESMAN: So you think a bidding process would set the best price after society has spent $2 billion building the transmission access out to the renewable area?

MS. JONES: Well, we believe it is more appropriate than just setting a price.

ASSOCIATE MEMBER GEESMAN: Now I have heard your procurement people talk long and hard

about the way bidders sometimes collude with each other to victimize your customers. Don't you think if you can determine the value of that renewable resource it might be more equitable and more transparent to simply set a price regulatorily?

MS. JONES: When you set a price regulatorily then you may be paying too much for some and not enough for others.

ASSOCIATE MEMBER GEESMAN: Perhaps.

MS. JONES: That's why we don't believe in the exercise of market power by bidders colluding, obviously. But we do think it is a little more fair than just setting a price.

Okay, renewables continued. The IEPR talks about updating the MPR protocols and we encourage the CEC to work with the PUC in their 2008 review of the MPR.

We also urge the CEC to work with the PUC and CARB to achieve the state's GHG goals at the lowest cost to ratepayers. This concerns the discussion of whether RPS should be included in the cap and trade system or not.

Distribution. We believe that the report talked about basing our utility's profits

on performance goals rather than investing in infrastructure. Based on the presentation today I am not sure that that is the message that was supposed to come across. I'm sorry to throw this at you.

MS. KELLY: I'm just trying to remember which one of those recommendations -- the utilities performance of goals, this is Linda Kelly, rather than investing in infrastructure. The point of the recommendation was to focus the investment on efficiency. I think that's the one. So if you just are investing based on large capital investments to increase bulk transfer, that's the way we have been doing things.

But I think the recommendation is to look at investing in efficiency measures. Can you incent the utility to reduce losses and operate the system more efficiently at the distribution level. Would that be a better way to the utility's profit motive rather than just incenting them to put in more transformers, more substations, et cetera.

MS. JONES: So it is one instead of the other or? I guess that's what I would like to clarify.

MS. KELLY: Well, I think it was in general to look at mechanisms that will rather than just on the bulk idea is look for other mechanisms, explore them. Because we see in other states and other countries that -- And when I say countries I mean primarily Canada, that are looking at ways to achieve goals that are not just large capital investments but to encourage them to have the utility operate their systems more efficiently. So that's where the profit basis is instead of just in buying or building large equipment to achieve various goals.

MS. JONES: I see, okay.

MS. KELLY: Is that clear?

MS. JONES: It is definitely clear to me. And I believe that the way I've portrayed it is somewhat incorrect so we'll go back to our comments and we'll fix this.

The last issue is funding distribution research to accelerate the transformation of the grid into an intelligent network. And as you know Edison has a significant investment in working to transform the grid.

But as you were speaking about the aging infrastructure, we recognize that as an issue and

we urge the CEC to encourage the PUC to provide priority funding for accelerated replacement of aging distribution infrastructure.

CPUC COMMISSIONER BOHN: Can I interrupt just for a second? I want to go back to the exchange we had before. On this one gets the sort of overwhelming feeling at some point that this great behemoth is just kind of lumbering forward. It's more of the same and more of the same and more of the same and we need to replace the old stuff with more old stuff. But it's now new and it's going to get old. How do you all propose to deal with new conceptual stuff?

I mean, I'm looking at this one particular piece. And we talked earlier about dealing with different things rather than just having infrastructure. What part of your organization deals with, gee whiz, maybe we ought to have distributed generation in this bottom quadrant of our area. I don't know whether that's good or bad or indifferent but what part of the organization deals with that as opposed to kind of dealing with the past?

MS. JONES: Well actually we deal with that on a daily basis. I can't remember the

specific name of the organization unfortunately, but there is an organization that is specifically dedicated to distributed generation. They look at areas of congestion, where it would be appropriate, is it cost-effective. That's their full-time job.

MS. KELLY: Can I -- this is Linda Kelly. This is sort of awkward, I wasn't expecting this. But I would like to answer that question as well because I think this is something that Southern California Edison and the other utilities are interested in.

But I think the place to look at that is in demonstration projects. I think that if you put together demonstration projects that have customers, a utility on board, this is the place that we can explore what works and doesn't work. And where all the parties involved participate and have this supported through the CPUC then I think that we can all together have a look at this and see what works, rather than just somebody going off and doing it on their own.

But these collaborative-type demonstrations I think are a great place to begin exploring these particular options and I think

this is something that we're very interested in developing with the utilities.

MS. JONES: And just in my closing comments if nobody has any other questions. Oh, the DG page. How could I forget this, oh my.

With respect to the IEPR's recommendation for creating tariffs to make DG projects cost and revenue neutral and eliminating the non-bypassable and standby reservation charges. We believe that creating special rates for specific technologies is unfair to retail customers.

COMMISSIONER BYRON: Excuse me.

MS. JONES: Yes.

COMMISSIONER BYRON: I'm curious. How do you come to the conclusion that if something is revenue neutral it is unfair for retail customers?

MS. JONES: Because the specific recommendation in the IEPR talked about giving additional benefits to DG projects based on congestion or other things. And if that is not something that is provided to other generation then it shouldn't be provided in a special case to DG.

And I guess last but not least is

developing a portfolio standard for distributed generation. All distributed generation is not created equal. Just like you have to look at the generation, your large book generation purchases, you have to look at the emissions and general profiles of small DG projects as well.

We believe that creating carve outs without specifics for performance requirements would potentially displace other lower cost, environmentally superior resources. And that is something that we would like to avoid.

COMMISSIONER BYRON: Excuse me but don't we have, quote, carve outs of other kinds? I mean, we have portfolio standards for renewables and energy efficiency and demand response.

MS. JONES: Yes we do.

COMMISSIONER BYRON: Are you saying that those also displace other lower cost, environmentally superior resources?

MS. JONES: Specifically renewable generation has the potential to do that depending on the type of generation. Some is more costly than others.

ASSOCIATE MEMBER GEESMAN: Well I wouldn't hesitate in thinking that you might be

able to find the most expensive out there. But on a statewide basis, 90 percent of the energy associated with the RPS contracts that the three IOUs have signed, 90 percent of that energy has come in below the market price referent.

MS. JONES: That's true. And not to toot Edison's horn but I believe that the people that work hard in the RPS solicitations do a really good job at managing that.

ASSOCIATE MEMBER GEESMAN: So shouldn't we want more of that?

MS. JONES: Well no, because if it is all out on a fair and level playing field then it will manage itself.

ASSOCIATE MEMBER GEESMAN: So if it weren't for the RPS program requirements that were created in state law, Edison probably would have found that cheaper energy anyway?

MS. JONES: Well actually Edison did have a significant amount of renewable energy before the RPS standard.

ASSOCIATE MEMBER GEESMAN: The graphs show you have less now than you did then.

MS. JONES: Well we have a larger customer base now. On a percentage basis, yes

that is true, but on a total quantity basis I don't believe that that's true.

ASSOCIATE MEMBER GEESMAN: Kind of like General Motors. Just because you're losing market share doesn't mean you're not still a good company.

MS. JONES: That's true. All right, now I think I'm done.

And in closing again I just want to say that Edison does in fact want to work collaboratively with the CEC in their ongoing processes for the 2008 update and the 2009 process. And most especially with respect to planning their future analyses. i think it would be really good to get stakeholder input. That wa we can all support the results when they come out.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much.

MS. JONES: Thank you.

PRESIDING MEMBER PFANNENSTIEL: We look forward to your comments on Friday.

Other comments on the Draft Committee Report? We have until this Friday for written comments to come in and we will have a busy weekend. So back to you Lorraine.

MS. WHITE: Thank you Commissioner. As you said, we are expecting the written comments on October 19 with the goal and objective of publishing your revised final report on November 7 and then going to the November 21 Business Meeting. With that we are concluded with presentations.

PRESIDING MEMBER PFANNENSTIEL: Well, with that we'll be adjourned. We'll be adjourned.

MS. WHITE: Thank you.

(Whereupon, at 3:00 p.m., the Committee workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, JOHN COTA, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 23rd day of October, 2007.